EPA's Responses to Public Comments on EPA's *National Emission Standards for Hazardous Air Pollutants for Major Source Industrial Commercial Institutional Boilers and Process Heaters*

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-2002-0058.*

FOREWORD

This document provides EPA's responses to public comments on EPA's Proposed *National Emission Standards for Hazardous Air Pollutants for Major Source Industrial Commercial Institutional Boilers and Process Heaters*. EPA published a Notice of Proposed Rulemaking in the Federal Register on June 4, 2010 at 75 FR 32005. EPA received comments on this proposed rule via mail, e-mail, facsimile, and at three public hearings held in Washington, DC, Houston, Texas, and Los Angeles, California in June 2010. 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 h*ttp://www.regulations.gov* by searching Docket ID *EPA-HQ-OAR-2002-0058.*

Due to the size and scope of this rulemaking, EPA paraphrased a limited amount of major comment themes in the preamble of the final rule. This document contains the verbatim comments provided by each commenter extracted from the original letter or public hearing transcript.

For each comment, the name and affiliation of the commenter, the document control number (DCN) assigned to the comment letter, and the number of the comment excerpt is provided. *Table 1* of this document provides a complete listing of the DCN and affiliations included in this document. In some cases the same comment excerpt was submitted by two or more commenters either by submittal of a form letter prepared by an organization or by the commenter incorporating by reference the comments in another comment letter. Rather than repeat these comment excerpts for each commenter, 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 2 and 3* at the end of this document.

Several of EPA's responses to comments are provided immediately following each comment excerpt. However, in instances where several commenters raised similar or related issues, EPA has grouped these comments together and provided a single response after the first comment excerpt in the group and referenced this response in the other comment excerpts. In some cases, 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, EPA has referenced the Preamble or the appropriate technical support document for a description of the analysis included in the final rule. In other cases EPA has provided a general response at the beginning of each section of this document.

Parallel with this rulemaking effort are three separate, but related rulemakings that may be of interest to stakeholders. These three rules are: *National Emission Standards for Hazardous Air Pollutants for Area Source Industrial/Commercial/Institutional Boilers* (Docket ID: EPA-HQ-OAR-2006-0790); *Identification of Non-Hazardous Secondary Materials That Are Solid Waste* (Docket ID: EPA-HQ-RCRA-2008-0329); and *Standards of Performance for New Stationary Sources and Emission Guidelines for Existing Sources: Commercial and Industrial Solid Waste Incineration Units* (Docket ID: EPA–HQ–OAR–2003–0119).
Given the identical proposal dates, and the related nature of these other rules, many commenters submitted comments to this rulemaking docket that were specific to one of these related rulemakings. Some commenters submitted a single DCN with comments on all four rules while others submitted a separate DCN specific to each rule. Many commenters submitted identical

comments to all of these dockets. In order to reduce duplicative comments, this document flags comments associated with any of the above three related rulemakings as out-of-scope comments for this response to comment document. To the extent that the commenter submitted these comments to the appropriate rulemaking document, responses have been developed in the response to comment documents for each of these related rulemakings. For this reason, EPA encourages the public to read the other response to comment documents prepared for these three other rulemakings as they may contain topics relevant to these other rulemakings.

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Rationale for Regulated Pollutants

Choice of Regulated Pollutants: Surrogates

Commenter Name: Norbord Industries
Commenter Affiliation: Norbord Industries
Document Control Number: EPA-HQ-OAR-2002-0058-0854.1
Comment Excerpt Number: 8

Comment: EPA has focused on setting limits with surrogates such as PM for metals and CO for HAPs. While establishing a PM standard and CO standard seems reasonable considering the potential complexity of testing for numerous pollutants, it also seems equally reasonable to establish an alternative standard for metals and other HAPs that focuses on the actual reduction of HAPs. The stringent requirements of Boiler MACT will make it difficult to meet some portions of the standard for many facilities such as ones with high HCl and PM (requiring multiple control devices). Though I could not predict what an alternative metal standard might entail it would likely increase the number of control options to facilities.

Response: See the response to comment EPA-HQ-OAR-2002-0058-2917.1, excerpt 9.

Commenter Name: Chris Greissing
Commenter Affiliation: Industrial Minerals Association
Document Control Number: EPA-HQ-OAR-2002-0058-2740.2
Comment Excerpt Number: 18

Comment: EPA justifies the use of PM as a surrogate for non-mercury metallic HAP on the basis that it "will also eliminate the cost of performance testing to comply with numerous standards for individual non-mercury metals." However, the supposed cost savings is illusory because PM CEMS certification is expensive. PM CEMS require a rigorous initial certification per 40 CFR 60 Appendix B Performance Specification 11, in which fifteen (15) Reference Method tests are conducted to develop the PM analyzer correlation. In addition, a Relative Response Audit must be conducted annually and a Response Correlation Audit must be performed every three years. The cost of initial certification could cost tens of thousands of dollars per unit with subsequent audits costing $5K to $8K per year.

Response: The non-Hg metal HAP are very likely to be present in the particulate phase and will be captured along with the filterable PM in the primary PM control device. The partitioning of the metal HAPs is very complicated and can depend upon the fuel type, the form of the metals in the fuel, other constituents in the fuel and the time-temperature profile of the post-combustion environment. EPA's Office of Research & Development has conducted studies that showed good control of the non-Hg metal HAP followed good control of bulk PM (filterable) across the primary PM control device. Furthermore, the applicability of PM CEMS is only to units >250 MMBtu/hr.

Commenter Name: Los Angeles Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1778
Comment Excerpt Number: 72

Comment: In any case, as should be the case with Boiler MACT facilities should have the option to comply with an emission limit for the HAP of concern rather than the surrogate; e.g., as an example, POM in lieu of CO.

Response: See the response to comment EPA-HQ-OAR-2002-0058-2917.1, excerpt 9.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-2702.1
Comment Excerpt Number: 191

Comment: Surrogates
CIBO supports the use of surrogates in the proposed Boiler MACT. EPA's use of surrogates for Non-mercury metallic HAP, Non-metallic inorganic HAP and Non-dioxin organic HAP is fully supported by long-standing case law. The D.C. Circuit has clearly held that "EPA may use a surrogate to regulate hazardous pollutants if it is reasonable to do so." Mossville Environmental Action Now v. EPA, 370 F.3d 1232, 1242 (D.C. Cir. 2004); Nat'l Lime, 233 F.3d at 634. In assessing the reasonableness of EPA's use of a surrogate in the Nat'l Lime case, the D.C. Circuit found that EPA satisfied this burden by demonstrating that there were always HAP metals in particulate matter (the surrogate), and thus that the removal of the particulate matter removed the HAP metals. Nat'l Lime, 233 F.3d at 639.

EPA's use of surrogates is well-supported by longstanding case law. Surrogates may be used for compounds regulated under section 112 where it is reasonable to do so and not otherwise contrary to law. Nat'l Lime Ass'n v. EPA, 233 F.3d 625, 637 (D.C. Cir. 2000); see also Kennecott Greens Creek Mining Company v. Mine Safety and Health Administration, 476 F.3d 946, 955 (D.C. Cr. 2007) ("there is nothing inherently problematic with an agency regulating one substance as a surrogate for another substance") (citing Nat'l Lime). In assessing the reasonableness of EPA's use of a surrogate, courts look to whether EPA has demonstrated a correlation between the HAP and the surrogate. Id.; see also Mossville Envt'l Action Now v. EPA, 370 F.3d 1232, 1242 (D.C. Cir. 2004) (invalidating use of vinyl chloride as surrogate where EPA failed to demonstrate correlation to HAP); Sierra Club v. EPA, 353 F.3d 976, 985 (D.C. Cir. 2004). While EPA's use of surrogates is supported by case law and by CIBO when appropriate, the following are comments that address outstanding issues with regard to EPA's use of surrogates in the Proposed Rule.

Response: EPA acknowledges the comment and agrees. It has finalized CO, PM, and HCl as surrogates in the final rule.

Commenter Name: Cathy S. Woollums
Commenter Affiliation: MidAmerican Energy Holdings Company
Document Control Number: EPA-HQ-OAR-2002-0058-2786.1
Comment Excerpt Number: 3

Comment: MidAmerican Does Not Support the Use of Surrogates for Certain Hazardous Air Pollutants – The use of surrogates is legally permissible. Specifically, the U.S. Court of Appeals in National Lime Association v. EPA [Footnote: 233 F.3d 625.} held that the EPA may use reasonable surrogates in setting technology based standards under section 112(d)(2) and (3) where the target pollutant is present in the surrogate, the control technology indiscriminately captures both the target and the surrogate and the control of the surrogate is the only means by which facilities can achieve reductions in the target HAPs.

In general terms, MidAmerican is supportive of the use of certain surrogates in this proposed rule. There is a large number of HAPs potentially present in emissions and as a result there are high costs and problems associated with accurately measuring and monitoring these HAP emissions. The use of surrogates can be beneficial to regulated entities by reducing the costs of both implementation and compliance with this proposed rule.

Response: EPA acknowledges the comment and agrees. It has finalized CO, PM, and HCl as surrogates in the final rule.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 67

Comment: ACC supports EPA's proposed use of surrogates. [The use of surrogates is supported by longstanding case law. The D.C. Circuit has clearly held that "EPA may use a surrogate to regulate hazardous pollutants if it is reasonable to do so and not otherwise contrary to law." In assessing the reasonableness of EPA's use of a surrogate in the Nat"l Lime case, the D.C. Circuit court has looked to whether EPA has satisfied this burden by demonstrating a correlation between the HAP and the surrogate, and thus that the removal of the surrogate matter removed the HAP. Nat"l Lime Ass"n v. EPA 233 F.3d 625,at 639 (D.C. Cir. 2000); Mossville Envt"l Action Now v EPA 370 F.3d 1232, 1242 (D.C. Cir. 2004) and Sierra Club v. EPA, 353 F.3d 976, 985 (D. C. Cir. 2004).]

Response: EPA acknowledges the comment and agrees. It has finalized CO, PM, and HCl as surrogates in the final rule.

Commenter Name: Paul J. Allen
Commenter Affiliation: Constellation Energy
Document Control Number: EPA-HQ-OAR-2002-0058-3164
Comment Excerpt Number: 3

Comment: Constellation supports use of surrogates for monitoring organics. Major source power plants already have Permits to Operate and/or Title V Permits that contain limits on emissions of criteria pollutants including CO and PM. Therefore, we suggest using these pollutant as surrogates, CO as a surrogate for non-dioxin organic HAP and PM a surrogate for non- and semi-volatile metal HAP, is suggested.

Response: EPA acknowledges the comment and agrees. It has finalized CO, PM, and HCl as surrogates in the final rule.

Commenter Name: Richard Rosvold
Commenter Affiliation: Xcel Energy Services, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2955.1
Comment Excerpt Number: 5

Comment: In general, we support the use of surrogates, rather than requiring limits for each individual hazardous air pollutant (HAP). Having individual limits for each chemical would be burdensome and would not provide any additional public health or environmental benefit.

Response: EPA acknowledges the comment and agrees. It has finalized CO, PM, and HCl as surrogates in the final rule.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 9

Comment: The Agency's proposed use of surrogates is appropriate as it ensures environmental protection while reducing the measurement burden on affected facilities. We note, however, that proposed CO emission limits for liquid- and gas-fired boilers are far beyond what is required to ensure HAP emissions are minimized.

ACC offers detailed suggestions on how EPA can improve the effort to consider fuel variability in the floor setting process.

Response: See the preamble for discussion on revised CO limits.

Commenter Name: Roy W. Wood
Commenter Affiliation: Eastman Kodak Company
Document Control Number: EPA-HQ-OAR-2002-0058-2917.1
Comment Excerpt Number: 9

Comment: An alternative means of establishing HAP compliance for the HAP surrogates, PM and CO, should be provided
The boiler MACT establishes emissions limits for 3 HAPs (mercury, HCl, dioxins) and two HAP surrogates (PM and CO). Control of the HAP surrogates is not required under the CAA. Rather EPA has proposed that these are reasonable surrogates for certain HAPs and these surrogates Junction as a more cost-effective means of controlling these HAPs. This reasoning is only valid to the extent that the selected surrogates truly correlate with the design HAPs. While there is some correlation between PM and HAP metals and some correlation between CO and organic HAPs, the correlation breaks down under a number of situations including low metals fuels and NOx reburn.

Because HAPs and the chosen surrogates do not correlate well across all boiler types, alternative compliance options should be available for the PM and CO standards which demonstrate compliance with HAP emissions instead of compliance with the surrogate standard.

Response: Carbon monoxide is often used as an indicator of combustion conditions. Under conditions of ideal combustion, a carbon-based or hydrocarbon fuel will completely oxidize to produce only CO2 and water. Under conditions of incomplete or non-ideal combustion, a greater amount of CO will be formed. With complex carbon-based fuels, combustion is rarely ideal and some CO and concomitant organic compounds are expected to be formed. Because CO and organics are both products of poor combustion, it is logical to expect that limiting the production of CO would also limit the production of organics. Because the non-Hg HAP metals are expected to be controlled using the same technologies that are applied for PM control, it seems logical to conclude that setting a standard that results in maximum achievable control of PM will result in good control of the non-Hg HAP metals.

Commenter Name: Barry Christensen
Commenter Affiliation: Occidental Chemical Corp
Document Control Number: EPA-HQ-OAR-2002-0058-2848.1
Comment Excerpt Number: 15

Comment: OCC supports EPA's use of surrogate parameters. For example, carbon monoxide is the more practical parameter to measure than individual organic HAPs. Similarly, establishing and controlling particulate is a practical way to limit the non-mercury metals. It is too costly and impractical to monitor and directly limit each individual HAP.

Response: EPA acknowledges the comment and agrees. It has finalized CO, PM, and HCl as surrogates in the final rule.

Commenter Name: Sarah E. Amick
Commenter Affiliation: Rubber Manufacturers Association
Document Control Number: EPA-HQ-OAR-2002-0058-2941.1
Comment Excerpt Number: 18

Comment: EPA's use of surrogates is well-supported by longstanding case law. Surrogates may be used for compounds regulated under section 112 where it is reasonable to do so and not otherwise contrary to law. Nat'l Lime Ass'n v. EPA, 233 F.3d 625, 637 (D.C. Cir. 2000); see also Kennecott Greens Creek Mining Company v. Mine Safety and Health Administration, 476 F.3d 946, 955 (D.C. Cr. 2007) ("there is nothing inherently problematic with an agency regulating one substance as a surrogate for another substance") (citing Nat'l Lime). In assessing the reasonableness of EPA's use of a surrogate, courts look to whether EPA has demonstrated a correlation between the HAP and the surrogate. Id.; see also Mossville Envt'l Action Now v. EPA, 370 F.3d 1232, 1242 (D.C. Cir. 2004) (invalidating use of vinyl chloride as surrogate where EPA failed to demonstrate correlation to HAP); Sierra Club v. EPA, 353 F.3d 976, 985 (D.C. Cir. 2004).

Response: EPA acknowledges the comment and agrees. It has finalized CO, PM, and HCl as surrogates in the final rule.

Commenter Name: Gary W. Kruger
Commenter Affiliation: Morton Salt
Document Control Number: EPA-HQ-OAR-2002-0058-2883.1
Comment Excerpt Number: 31

Comment: Morton Salt supports the use of surrogates in the proposed Boiler MACT. The D.C. Circuit has clearly held that EPA may use a surrogate to regulate hazardous pollutants if it is reasonable to do so. Mossville Environmental Action Now v. EPA, 370 F.3d 1232, 1242 (D.C. Cir. 2004); Nat'l Lime, 233 F.3d at 634. In assessing the reasonableness of EPA's use of a surrogate in the Nat'l Lime case, the D.C. Circuit found that EPA satisfied this burden by demonstrating that there were always HAP metals in particulate matter (the surrogate), and thus that the removal of the particulate matter removed the HAP metals. Nat'l Lime, 233 F.3d at 639.

Response: EPA acknowledges the comment and agrees. It has finalized CO, PM, and HCl as surrogates in the final rule.

Choice of Regulated Pollutants: THC vs. CO vs. Other Organic HAP

Commenter Name: Thomas J. Christofk
Commenter Affiliation: Placer County Air Pollution Control District
Document Control Number: EPA-HQ-OAR-2002-0058-1598.1
Comment Excerpt Number: 2

Comment: Placer County Air Pollution Control District (PCAPCD) supports the use of a CO limit as a surrogate for non-dioxin organic hazardous air pollutants. CO limits, and the use of CO continuous emissions monitoring systems, are a part of existing Placer County and State of California biomass boiler operating permits.

Response: EPA acknowledges the comment and agrees. It has finalized CO as a surrogate in the final rule.

Commenter Name: Los Angeles Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1778
Comment Excerpt Number: 78

Comment: Your standard identifies specific
chemicals that we feel is not adequate. There are over
0 00 plus toxic HAP chemicals that have been identified
and we want a standard to be applied to every single one
of them. You have stated in there that you have
identified or called a category of a surrogate or CO,
for example. Well, you can’t compare a thousand pounds
of benzene to a thousand pounds of CO by averaging.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3187.1, excerpt 15.

Commenter Name: James P. Brooks
Commenter Affiliation: Maine Department of Environmental Protection, Bureau of Air Quality
Document Control Number: EPA-HQ-OAR-2002-0058-2746.1
Comment Excerpt Number: 1

Comment: In 2009, the Maine DEP requested stack testing information from Maine's biomass and multi-fuel boilers to evaluate the relationship between CO, NOx, POM and metallic HAPs. The Maine DEP submitted its report Carbon Monoxide Variability in Maine Wood-Fired Boilers to EPA in March 2010. A copy of the report accompanies this letter for submission to the docket. The Maine DEP's analysis revealed wide variations in CO emission rates from single units resulting from variations in biomass moisture content and the types of additional materials co-combusted with the biomass. In the report, we concluded:

EPA should NOT utilize CO as a surrogate for HAP in wood fired and multi-fueled boilers. The data illustrates that CO is extremely variable in wood fired/multi-fueled boilers. An inappropriately low CO standard may result in facilities burning significantly more fossil fuels to reduce variability and meet a CO standard. Alternatively, a facility may choose add-on CO control equipment which would control CO but not HAPs.

EPA should develop a standard for gaseous HAP using VOC, TOC, or THC as a surrogate as utilized in several other combustion NESHAP.

If EPA chooses to use CO as a surrogate for HAP, EPA should take into account the inherent variability encountered when combusting only wood.

Response: EPA thanks the commenter for their input, but EPA's Office of Research and Development does not support the use of THC as a surrogate for organic HAP from industrial boilers. See preamble for response to comments on how CO limits were modified.

Commenter Name: Arthur N. Marin
Commenter Affiliation: NESCAUM
Document Control Number: EPA-HQ-OAR-2002-0058-2893.1
Comment Excerpt Number: 2

Comment: NESCAUM has serious concerns with the proposed CO limits in both rules. First and foremost, NESCAUM states do not concur with the assumption that, at lower emission levels, CO is an appropriate surrogate for reducing polycyclic organic matter (POM) emissions. Analyses by states of this issue support this conclusion. If EPA's position is that increased combustion will result in lower emission levels of organics, then we suggest that EPA use a combustion efficiency limit and test method rather than a CO standard. For existing units, EPA should require annual tune-up and testing of combustion efficiency (oxidative). For new units, EPA should require that they meet the U.S. Department of Energy's AFUE standards for direct heating devices and boilers or ASHRAE155p standards.
If EPA chooses to continue to use CO as a surrogate for POM emissions, we recommend that it re-evaluate its approach towards emission limits and control options for CO. Increasing combustion efficiency may reduce POM emissions, but the use of CO controls may not. Furthermore, the proposed CO limits may be unachievable for some existing units. If such a unit has NOx limits, then it will need to install add-on CO controls to these units, likely CO catalysts, which will do nothing to reduce HAP emissions. If a unit does not have NOx emission limits, it

may increase NOx emissions in order to reduce its CO emissions, once again with little impact on its overall HAP emissions. NESCAUM recommends that EPA use a multi-pollutant approach to re-evaluate the proposed CO emission limits in light of the potential negative impacts of the CO limits on the emissions of other air pollutants.

Response: Carbon monoxide is often used as an indicator of combustion conditions. Under conditions of ideal combustion, a carbon-based or hydrocarbon fuel will completely oxidize to produce only CO_2 and water. Under conditions of incomplete or non-ideal combustion, a greater amount of CO will be formed. With complex carbon-based fuels, combustion is rarely ideal and some CO and concomitant organic compounds are expected to be formed. Because CO and organics are both products of poor combustion, it is logical to expect that limiting the production of CO would also limit the production of organics. As such, EPA is not including other options for compliance with respect to non-dioxin organic HAP; all units must meet CO limits.

Based on comments received there was insufficient data to determine if a lower threshold for CO exists. For example different thresholds were provided (100 vs 500 ppm). In the absence of specific data we computed the CO MACT floors using the data available. Also, since proposal many of the CO limits have increased, see the preamble for further discussion.

Regarding the use of oxidation catalysts to reduce organic HAP, there are permits for biomass units through the Florida Department of Environmental Protection which show organic HAP reductions via oxidation catalysts. See information for DEP File No. 0810226-001-AC.

Commenter Name: Robert R. Scott
Commenter Affiliation: New Hampshire Department of Environmental Services, Air Resources Division
Document Control Number: EPA-HQ-OAR-2002-0058-2734.1
Comment Excerpt Number: 2

Comment: The proposal uses carbon monoxide (CO) as a surrogate for polycyclic organic matter (POM) and other urban organic HAPs.

EPA is proposing to use CO as a surrogate for organic HAPs, including POM, emitted from various fuels burned in boilers because the presence of CO is an indicator of incomplete combustion and possibly an indicator of elevated organic HAP emissions. In addition, monitoring equipment and measuring of CO is more readily available and cost effective than measuring and monitoring individual organic HAPs. While NHDES recognizes that using a surrogate for HAPs in this proposal is more practical than imposing individual standards for each specific HAP, NHDES is concerned that setting a CO limit in this regulation could potentially result in facilities installing CO controls to meet the CO emission limits in the rule instead of improving the efficiency of the boiler to reduce HAP emissions, especially if the CO emission limitations set by the rule are exceedingly restrictive. There has been some indication from various studies that reducing CO emissions to reduce HAP emissions is only effective to a certain point and that below that level, HAP emissions are no longer effectively reduced.

NHDES recommends that if EPA continues to use CO as a surrogate for HAPs, that EPA research the available data to confirm this break even point and set CO emission levels such that the intent of the rule (reduction in HAP emissions) is actually achieved by the rule.

Response: See the response to comment EPA-HQ-OAR-2002-0058-2792.1, excerpt 73.

Commenter Name: Charles R. Faulds
Commenter Affiliation: Texas Electric Cooperatives, Treating Division
Document Control Number: EPA-HQ-OAR-2002-0058-2526.1
Comment Excerpt Number: 3

Comment: EPA established limits for CO, but should focus on ensuring boilers have good combustion practices.

Response: See the preamble for discussion on setting MACT standards and how CO limits were modified.

Commenter Name: James P. Brooks
Commenter Affiliation: Maine Department of Environmental Protection, Bureau of Air Quality
Document Control Number: EPA-HQ-OAR-2002-0058-2746.1
Comment Excerpt Number: 5

Comment: EPA's own proposed standards support the conclusion that CO is an inappropriate surrogate for organic HAPs. Dioxin is an organic HAP, but is addressed independent of the other organic HAP supposedly covered by the CO standards. As required by Section 112, the proposed standards are based on actual emission rates reported by facilities. Where the proposed dioxin limits were low, CO limits were higher and vice versa. We believe this supports our findings that CO emissions do not trend with organic HAPs, and therefore CO is a poor surrogate. We recommend that EPA more carefully consider these relationships and the implications of regulating CO emissions instead of EPA's target pollutants.

Response: Carbon monoxide is often used as an indicator of combustion conditions. Under conditions of ideal combustion, a carbon-based or hydrocarbon fuel will completely oxidize to produce only CO2 and water. Under conditions of incomplete or non-ideal combustion, a greater amount of CO will be formed. With complex carbon-based fuels, combustion is rarely ideal and some CO and concomitant organic compounds are expected to be formed. Because CO and organics are both products of poor combustion, it is logical to expect that limiting the production of CO would also limit the production of organics. Dioxins/furans, however, are produced by mechanisms (often catalytic) downstream of the combustion zone and are not related to the amount of CO present in the flue gas. EPA does not have sufficient data to set a separate emission limit for organic HAP.   As such, EPA is not including other options for compliance and all units must meet CO and dioxin/furan limits.

Based on comments received there was insufficient data to determine if a lower threshold for CO exists. For example, different thresholds were provided (100 vs 500 ppm). In the absence of specific data we computed the CO MACT floors using the data available. Also, since proposal many of the CO limits have increased, see the preamble for further discussion.

Regarding the use of oxidation catalysts to reduce organic HAP, there are permits for biomass units through the Florida Department of Environmental Protection which show organic HAP reductions via oxidation catalysts. See information for DEP File No. 0810226-001-AC.

Commenter Name: James P. Brooks
Commenter Affiliation: Maine Department of Environmental Protection, Bureau of Air Quality
Document Control Number: EPA-HQ-OAR-2002-0058-2746.1
Comment Excerpt Number: 6

Comment: We also recommend that EPA review emissions data based on boiler systems and not individual pollutants. Most of EPA's selected "best performing units" can meet the proposed standard for one pollutant, but not the others (i.e. most of EPA's best performing units could not comply with all elements of proposal simultaneously).

Response: See preamble for response to comments on the pollutant-by-pollutant approach.

Commenter Name: Steven M. Maruszewski
Commenter Affiliation: The Pennsylvania State University
Document Control Number: EPA-HQ-OAR-2002-0058-2729.1
Comment Excerpt Number: 7

Comment: The background information indicates the CO limitations are included as a surrogate for organic HAPs. We question the use of CO as a surrogate on a number of points. [See submittal for Tables]
EPA consider development of an alternative surrogate for organic HAP such as THC.

Response: EPA thanks the commenter for their input, but EPA's Office of Research and Development does not support the use of THC as a surrogate for organic HAP from industrial boilers. See preamble for response to comments on how CO limits were modified.

Commenter Name: N/A
Commenter Affiliation: Sierra Club, Clean Air Task Force, Earthjustice, and Natural Resources Defense Council

Document Control Number: EPA-HQ-OAR-2002-0058-3187.1
Comment Excerpt Number: 13

Comment: EPA's choice of CO as a surrogate for organic HAPs violates the requirements of CAA section 112(c)(6).
Section 112(c)(6) of the Act requires "[w]ith respect to" certain listed highly toxic HAPs, including the carcinogenic POM and PCBs, the Administrator "shall ...list categories and subcategories of sources assuring that sources accounting for not less than 90 per centum of the aggregate emissions of each such pollutant are subject to standards under subsections [112](d)(2) or (d)(4) ...." 42 U.S.C. § 7412(c)(6)(emphasis added). Section 112(c)(6) thus provides the public with extra protection from these exceptionally toxic HAPs – by requiring listed sources of each such pollutant to be subject to MACT-based standards. Regardless of what authority EPA might have to use surrogates for other hazardous air pollutants, the agency must set specific emission standards under § 112(d)(2) or (d)(4) for the highly toxic HAP enumerated in § 112(c)(6).

In 1998, EPA listed 'industrial coal combustion' industrial oil combustion,' 'industrial wood/wood residue combustion,' commercial coal combustion,' 'commercial oil combustion,' and 'commercial wood/wood residue combustion,' under section 112(c)(6). 75 Fed. Reg. 32,008, 32,042 (citing 63 Fed. Reg. 17838, 17848 (April 10, 1998)). While EPA asserts that the 1998 listing was on the basis of emissions of POM and mercury, 75 Fed. Reg. 32,008, that alone is not enough to permit the Agency to escape the requirement to set MACT standards for all the 112(c)(6) pollutants it now knows are emitted by ICIBPH, which include not only POM, and mercury, but also PCBs.

Specifically, EPA claims that it has met its obligations under § 112(c)(6) by setting by setting carbon monoxide (CO) standards, and that "POM is effectively reduced by the combustion and post-combustion practices require to comply with the [other] CAA section 112 standards." 75 Fed. Reg. 32,042. But this is not enough to satisfy the requirements of the stateute. First, EPA makes no mention of the other §112(c)(6) pollutants emitted by ICIBPH, and how they might be affected by this proposal. Second, nothing in the statute's language authorizes EPA to use a surrogate to regulate POM, or any of the other pollutants specifically enumerated in §112(c)(6), including the PCBs also emitted by ICIBPH. EPA's attempt to do so in fact contravenes the plain language requirements of the statute. Third, § 112(c)(6) requires the Agency to "assure" that sources of these pollutants are regulated by MACT-based standards – so that "not less than 90 percentum of the aggregate emissions of each such pollutant" are so regulated. 42 U.S.C. § 7412(c)(6). It is implausible to quantify the degree to which emissions of POM and PCBs are lowered by standards that only set limits on – and demand compliance for the CO surrogate. Nor is EPA's "belief" that CO serves as an effective surrogate for POM sufficient. And finally, it is not enough to satisfy the requirement of §112(c)(6) to say, as EPA does, merely that because "the emissions tests obtained at currently operating units show that the proposed MACT regulations will reduce mercury emissions by about 86 percent," it is somehow "reasonable to assume that POM emissions will [also] be substantially controlled." 75 Fed. Reg. 32,042 (emphasis added).

CO is not a sufficient lawful surrogate for any organic HAP, including for POM or PCBs. And, while EPA agrees that "standards established under section 112(d)(2) must reflect the performance of MACT, 75 Fed. Reg. 32,008, there is no demonstrated correlation in the record for this proposal between levels of the CO surrogate and levels of emissions of POM, or PCBs emitted by ICIBPH. Nor is there any demonstration that the CO proposed floors will provide the equivalent health and environmental protection provided by a MACT floor standard if one were set for each of those pollutants. EPA therefore cannot "assure" through use of a surrogate that this listed industry's §112(c)(6) pollutant emissions are controlled to the level required by 112(d)(2) as it could if separate MACT floors were set, and compliance with those floors required, for those carcinogenic organics. Even if CO were a valid surrogate, though, on this record, § 112(c)(6) requires EPA to set § 112(d)(2) or (d)(4) standards with respect to POM and PCBs.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3187.1, excerpt 15.

Commenter Name: N/A
Commenter Affiliation: Sierra Club, Clean Air Task Force, Earthjustice, and Natural Resources Defense Council
Document Control Number: EPA-HQ-OAR-2002-0058-3187.1
Comment Excerpt Number: 14

Comment: CO is not a lawful surrogate for any organic HAPs.

EPA says that it considered both total hydrocarbon (THC) and CO as surrogates, but chose CO because "CO has generally been used as a surrogate for organic HAP because CO is a good indicator of incomplete combustion and organic HAP are products of incomplete combustion." 75 Fed. Reg. 32,018. EPA correctly recognizes that this is not true for dioxin and furans, as these organic HAPs can be formed outside of the combustion unit, not as part of the combustion process, and so sets separate standards for these carcinogens. But for the remaining organic HAP, EPA simply states that "minimizing CO emissions will result in minimizing non-dioxin organic HAP. Methods for the control of [these HAP] would be the same methods used to control CO emissions. These emission control methods include achieving good combustion or using an oxidation catalyst." Id. EPA further asserts that "establishing emission limits for specific organic HAP (with the exception of D/F) would be impractical and costly." Id. None of these reasons is sufficient to support the selection of CO as a surrogate, over the requirement to set emissions standards for specific organic HAPs.

Response: See the response to comment EPA-HQ-OAR-2002-0058-2746.1, excerpt 5.

Commenter Name: N/A
Commenter Affiliation: Sierra Club, Clean Air Task Force, Earthjustice, and Natural Resources Defense Council
Document Control Number: EPA-HQ-OAR-2002-0058-3187.1
Comment Excerpt Number: 15

Comment: EPA does not assert that organic HAP are "invariably present" when CO is present – only that CO indicates incomplete combustion and in those conditions the organic HAP are present. Second, while EPA says that "minimizing CO emissions will result in minimizing non-dioxin organic HAP," the agency does not assert in the preamble, and there is nothing in the record to indicate that this relationship is indiscriminate – i.e., that all the non-dioxin organics will always be minimized when CO are minimized. Indeed, EPA cannot make this assertion.

There are three classes of non-dioxin/furan organic HAPs that behave differently during combustion: (1) volatile organic compounds, which are gases; (2) semi-volatile organic compounds, which may be gases or solids, depending on where in the exhaust gas train they are; and (3) particulate organic compounds, such as polynuclear aromatic compounds, which are present in the particulate fraction. [See submittal for Reference 10.] A single indicator, CO, cannot be used as a surrogate for these three diverse groups of chemicals because they are chemically and physically dissimilar. Most of the particulate organic compounds for example, form primarily immediately downstream of the combustion chamber, as do dioxin/furans. This is far from the same mechanism by which CO is formed. Several of these compounds are not products of incomplete combustion, like CO, but rather are formed via distinct chemical reaction pathways. Polynuclear aromatic hydrocarbons are formed in condensation reactions, for example. [See submittal for Reference 11.]

Because of these diverse physical relationships, CO minimization or control does not indiscriminately minimize or capture non-dioxin/furan organic HAPs. Additionally sources can achieve lowered emissions of such organic HAP emissions by means other than CO control. For example, "combustion optimization" is a typical means that is used to control carbon monoxide. This includes changes in combustion residence time, turbulence, and temperature. Yet, combustion optimization can actually increase some organic HAPs (such as polynuclear aromatic hydrocarbons) while reducing others (such as VOCs). Other carbon monoxide controls, such as substituting alternative fuels (natural gas, or distillate oil), would reduce such organic HAPs at a far higher rate than methods for the limitation of carbon monoxide.

Response: Carbon monoxide is often used as an indicator of combustion conditions. Under conditions of ideal combustion, a carbon-based or hydrocarbon fuel will completely oxidize to produce only $CO2$ and water. Under conditions of incomplete or non-ideal combustion, a greater amount of CO will be formed. With complex carbon-based fuels, combustion is rarely ideal and some CO and concomitant organic compounds are expected to be formed. Because CO and organics are both products of poor combustion, it is logical to expect that limiting the production of CO would also limit the production of organics. As such, EPA is not including other options for compliance with respect to non-dioxin organic HAP; all units must meet CO limits.

Based on comments received there was insufficient data to determine if a lower threshold for CO exists. For example different thresholds were provided (100 vs 500 ppm). In the absence of specific data we computed the CO MACT floors using the data available. Also, since proposal many of the CO limits have increased, see the preamble for further discussion.

Regarding the use of oxidation catalysts to reduce organic HAP, there are permits for biomass units through the Florida Department of Environmental Protection which show organic HAP reductions via oxidation catalysts. See information for DEP File No. 0810226-001-AC.

Commenter Name: Stephen R. Gossett
Commenter Affiliation: Eastman Chemical Company
Document Control Number: EPA-HQ-OAR-2002-0058-3137.1
Comment Excerpt Number: 16

Comment: Total hydrocarbons (THC) needs to be added as an alternative standard to CO as a surrogate for non-dioxin organic HAPs.

EPA has elected to propose CO as a surrogate for non-dioxin organic HAPs and is requiring CO CEMS for units larger than 100 mmBtu/hr. Compliance with the CO emission standard is then determined on a 30 operating day rolling average basis. While we have concerns that the MACT floor emission limitations do not properly account for load variation or periods of startups and shutdowns, we believe, that once the CO MACT floor level is properly determined, compliance with a CO limit will be the preferred method in many cases. However, Eastman requests that EPA set an alternative THC standard. The Hazardous Waste Combustor MACT (40 CFR 63 Subpart EEE) provides an option of a 100 ppm CO limit or a 10 ppm THC limit. While most hazardous waste incinerator operators selected the CO option, Eastman has selected the THC option at three of our incinerators and have found the THC CEMS, while more costly, to be a workable option.

Also, we have a case where THC may be much preferable to a CO limit. Eastman's largest and newest boiler is a wall-fired PC boiler which was installed with advanced combustion controls (low NOx burners and over-fire air system) to control NOx, plus a Spray Dryer Absorber (SDA) and Fabric Filter for control of acid gases. Preliminary CO CEMS data indicates this boiler will have difficulty attaining the proposed CO limit for PC boilers. Our experience with other solid fuel units shows us that THC levels are often more stable and less reactive to load swings than CO. Since THC really is a better indicator of non-dioxin organic HAPs that CO (CO is not a HAP whereas much of the THCs are HAPs), there is no reason EPA cannot grant our request and provide a THC option. Without the THC option, Eastman is likely to be faced with a very costly choice: either install a capital intensive CO catalytic reduction system; or remove the most modern and most effective combustion controls for NOx at this site to control CO, and install very expensive post-combustion NOx reduction technologies such as Selective Catalytic Reduction (SCR). Please note that industry experience advises against the use of less capital intensive NOx control technologies like Selective Non-Catalytic Reduction (SNCR) on units equipped with SDA's, due to the negative downstream effects of ammonia slip on personnel safety (NH_3 release in recycle slurry) and the reliability of downstream components (formation of fouling ammonium salts). Further note that either of these options will significantly increase system draft loss, which will likely require a new ID fan at considerable expense. Eastman does not believe that the enormous capital expense these options present are justified, given that such a solution reduces CO but may not actually reduce non-dioxin organic HAPs. Eastman believes that this is a classic case of unintended consequences with little commensurate benefit to health or the environment.

Response: EPA thanks the commenter for their input, but EPA's Office of Research and Development does not support the use of THC as a surrogate for organic HAP from industrial boilers. See preamble for response to comments on how CO limits were modified.

Commenter Name: N/A
Commenter Affiliation: Sierra Club, Clean Air Task Force, Earthjustice, and Natural Resources Defense Council
Document Control Number: EPA-HQ-OAR-2002-0058-3187.1
Comment Excerpt Number: 16

Comment: EPA does not note these limitations on using CO as a surrogate for non-D/F organics. In fact, evidence from the test data show that EPA's testing protocols were designed from the beginning to test only for CO, not the organic HAPs for which it stands as a surrogate. Major Source ICR Testing Protocol Summary Supporting Statement at 7 (EPA-HQ-OAR-2002-0058- 0801. EPA therefore cannot show that CO and organic HAP are invariably present together and that minimizing or controlling CO always minimizes or controls all the organic HAP. Indeed, the results of those tests show that even for a single source, CO emissions differ radically from test to test – for the best performing coal-fired source for CO, EPA's data show: [See submittal for Table III-2 Data for EPA's Best-performing Coal Fired Source for CO.]

Response: See the response to comment EPA-HQ-OAR-2002-0058-3187.1, excerpt 15.

Commenter Name: N/A
Commenter Affiliation: Sierra Club, Clean Air Task Force, Earthjustice, and Natural Resources Defense Council
Document Control Number: EPA-HQ-OAR-2002-0058-3187.1
Comment Excerpt Number: 17

Comment: Third, and most notably, EPA does not assert that measures for the control of CO are the only means by which facilities 'achieve' lower emissions of non D/F organic HAP. Instead EPA relies on a cost-related argument to reject the idea of setting individual HAP-specific emissions limits for each of the non-D/F organic HAPs, noting that "CO, which is less expensive to test for and monitor, is appropriate for use as a surrogate," and that this is true despite the fact that "the level and distribution of organic HAP associated with CO emissions will vary from unit to unit." In other words, EPA cannot say, as it must to satisfy the Sierra Club test for the use of surrogates, that controls on or minimization of CO are the only method for controlling organic HAPs. EPA can only say, as it has, that relying on CO control as a surrogate for individualized MACT emissions limits for these HAPs will "eliminate costs associated with speciating numerous compounds." Id. EPA can't choose a surrogate just because it's cheaper. EPA must show that the surrogate actually meets the test for valid surrogates established by the D.C. Circuit. The agency has failed to do so here.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3187.1, excerpt 15.

Commenter Name: N/A
Commenter Affiliation: Sierra Club, Clean Air Task Force, Earthjustice, and Natural Resources Defense Council
Document Control Number: EPA-HQ-OAR-2002-0058-3187.1
Comment Excerpt Number: 19

Comment: EPA clearly has failed to show that the CO surrogate meets the Sierra Club 3-part test for an effective surrogate for non-D/F organic HAPs. That deficiency might be cured if EPA in its background material or preamble provided a reasoned explanation , supported by substantial record evidence why using the CO surrogate otherwise will or can ensure that each of the organic HAPs that are emitted by various subcategories of ICIBPH will be controlled to the level of the relevant best performing sources, with respect to each of those HAPs. The Agency has not done so, however, and so its reliance on the CO surrogate is unreasonable.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3187.1, excerpt 15.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 95

Comment: In this proposal CO is established as a surrogate for organic HAP. Minimizing CO is, therefore, intended to demonstrate that organic HAP is minimized. It appears clear however that the level of organic HAP emissions becomes insensitive to CO concentration below some value (e.g., 100 ppm).
EPA itself has already reached this conclusion in the Hazardous Waste NESHAP rulemaking. As the Agency states at 70 FR 59462 (October 12, 2005):
We explained at proposal why the carbon monoxide standard of 100 ppmv and the hydrocarbon standard of 10 ppmv are appropriate floors. See 69 FR at 21282. The floor level for carbon monoxide of 100 ppmv is a currently enforceable Federal standard. Although some sources are achieving carbon monoxide levels below 100 ppmv, it is not appropriate to establish a lower floor level because carbon monoxide is a conservative surrogate for organic HAP. Organic HAP emissions may or may not be substantial at carbon monoxide levels greater than 100 ppmv, and are extremely low when sources operate under the good combustion conditions required to achieve carbon monoxide levels in the range of zero to 100 ppmv. (See also the discussion below regarding the progression of hydrocarbon oxidation to carbon dioxide and water). As such, lowering the carbon monoxide floor below 100 ppmv may not provide significant reductions in

organic HAP emissions. Moreover, it would be inappropriate to establish the floor blindly using a mathematical approach—the average emissions for the best performing sources—because the best performing sources may not be able to replicate their emission levels (and other sources may not be able to duplicate those emission levels) using the exact types of good combustion practices they used during the compliance test documented in our data base. This is because there are myriad factors that affect combustion efficiency and, subsequently, carbon monoxide emissions. Extremely low carbon monoxide emissions cannot be assured by controlling only one or two operating parameters.

AF&PA agrees that CO is an appropriate surrogate for organic HAP, but believe HAP emissions are minimized at levels well above the 1 or 2 ppm CO proposed for gas 2 and liquid boilers. As EPA concludes above, at CO levels below about 100 ppm, differences in organic HAP emissions are negligible. Where achievable emission limitations for organic HAP that properly reflect source category and unit variability are derivable from representative data, CO should continue to be used as the compliance surrogate for organic HAP. However, the CO limits should reflect the fact that the organic HAP concentration becomes insensitive to CO level below some value (e.g., 100 ppm).

Response: See the response to comment EPA-HQ-OAR-2002-0058-2792.1, excerpt 73.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 190

Comment: The use of CO as a surrogate for the reduction of organic compounds is not new. For example, CO was used as an indicator of combustion efficiency as part of the Interim Status rule for Boilers and Industrial Furnaces (BIFs) that burn hazardous waste. At the time, EPA's research demonstrated that BIF units with CO emissions less than 100 ppmvd were achieving the desired destruction efficiency of the hazardous organics in the waste streams. As mentioned previously, because the chemical kinetics make CO far more difficult to oxidize than other organic compounds, it is not necessary to drive CO emissions to zero to obtain a corresponding minimization of organic emissions.
The data used to support the BIF Interim Status rule documented how the selected level of CO corresponded to minimal emissions of the target compounds. That should be the case for Boiler MACT as well. It is not logical to apply the same rules to establish a CO floor, when CO is merely the surrogate. It is more reasonable to collect data that demonstrate low organic emissions, and then to document the corresponding CO emissions for those sources.

Response: See the response to comment EPA-HQ-OAR-2002-0058-2792.1, excerpt 73.

Commenter Name: Timothy Hunt

Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 191

Comment: Another aspect of CO emissions that make them a poor candidate for establishing a MACT floor as a surrogate for organic HAP is that CO emissions may vary significantly, without any adjustments being made to the boiler controls. For example, in a wood-fired boiler with a traveling grate, variations in the composition or moisture content of the wood may cause it to pile on the grate and smolder, leading to elevated CO emissions.

Response: See the preamble for discussion on how CO limits were modified.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 186

Comment: Carbon monoxide is the most common product of incomplete combustion (PIC), and because of its associated chemical kinetics, is one of the most difficult PICs to oxidize completely. As such, CO emissions have historically been used as an indicator of the quality of the combustion process. The concept is that low CO emissions would equate to negligible emissions of other organic compounds. While this is true in general, the mechanisms by which CO is formed and destroyed in the combustion process are different than for other organics. As such, in cases where other organic compounds have been completely oxidized, CO concentrations may still be elevated. While the tendency is to think that further reductions in CO emissions will improve the quality of the combustion, and in turn minimize emissions of other organic compounds, this is not necessarily true. Instead, forcing CO emissions lower and lower ends up over-constraining the combustion process, producing negative impacts on other air quality concerns, without documented improvements in emissions of organics.

Response: See the response to comment EPA-HQ-OAR-2002-0058-2792.1, excerpt 73.

Commenter Name: Chris Greissing
Commenter Affiliation: Industrial Minerals Association
Document Control Number: EPA-HQ-OAR-2002-0058-2740.2
Comment Excerpt Number: 8

Comment: It is Appropriate to Use CO as a Surrogate but EPA did not Establish Achievable CO Emission Standards. We concur with the use of CO as a surrogate because establishing MACT limits for individual organic HAP would be impractical and costly. 75 Fed. Reg. at 32018. However, there are significant flaws regarding the CO limits that EPA proposes because they do not account for variation in CO emissions that can result from unit design and operation and which do not necessarily vary in proportion to organic HAP emissions. Because of this variation, it is essential that CO MACT limits be set at levels that can be met under all reasonably expected adverse conditions.

Response: See preamble for response to comments on how CO limits were modified.

Commenter Name: W. Randall Rawson
Commenter Affiliation: American Boiler Manufacturers Association
Document Control Number: EPA-HQ-OAR-2002-0058-2698.1
Comment Excerpt Number: 9

Comment: EPA has not adequately identified its basis for using CO as a surrogate for polycyclic organic matter ("POM"). ABMA acknowledges a correlation between CO and organic HAPs; however, ABMA is not aware of any relevant testing data that correlates the relationship between HAPs and CO when operating at CO levels less than 100 ppm. By contrast, data from the Petroleum Environmental Research Forum Project 92-19 provides some of the most complete data examining the relationship between CO and HAPs during gas firing. While there is a fairly linear correlation between decreasing CO and decreasing HAPs at higher levels, once the CO values fall under 100 ppm, further reduction of CO did not provide any substantial correlating reduction of HAPs. Based on this data, it can be concluded that during gas firing the reduction of CO from 100 ppm to 1 ppm may not create any incremental benefit in terms of HAP reductions. Without any data to the contrary, this relationship between CO and HAPs should also be applied to oil-firing, where EPA has not demonstrated that a significant HAP reduction would occur at CO levels below 100 ppm.

Response: See the response to comment EPA-HQ-OAR-2002-0058-2792.1, excerpt 73.

Commenter Name: Chris Greissing
Commenter Affiliation: Industrial Minerals Association
Document Control Number: EPA-HQ-OAR-2002-0058-2740.2
Comment Excerpt Number: 11

Comment: Moreover, EPA has not done the analysis to establish a correlation between CO emissions and organic HAP emissions at all levels of CO. Although there may be a general directional correlation between the incomplete combustion products of CO and organic HAP, empirical data shows that reducing CO levels below 100 ppm does not result in appreciable further reductions in organic HAP. The CO MACT limits should reflect this fact, and further reductions in CO below 100 ppm should not be required because such reductions do not result in further HAP removal. The purpose of MACT limits is to reduce HAP, not to reduce CO for its own sake where there is no added benefit of further HAP reduction.

Response: See the response to comment EPA-HQ-OAR-2002-0058-2792.1, excerpt 73.

Commenter Name: Leonard W. Sandridge
Commenter Affiliation: University of Virginia
Document Control Number: EPA-HQ-OAR-2002-0058-2769.1
Comment Excerpt Number: 12

Comment: The preamble indicates that CO serves as a surrogate for non-dioxin organic HAP emissions. Emission controls for CO include achieving good combustion or using an oxidation catalyst. In other MACT regulations, such as 40 CFR 64 Subpart EEE, CO emissions of up to 100 ppm have been considered as indicators of good combustion and have been correlated to levels of non-dioxin organic HAP emissions that are protective of human health and the environment, as demonstrated by the results of comprehensive multi-pathway human health and ecological risk assessments for hazardous waste combustors.

Response: See the response to comment EPA-HQ-OAR-2002-0058-2792.1, excerpt 73.

Commenter Name: David A. Buff
Commenter Affiliation: Golder Associates Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2801.1
Comment Excerpt Number: 27

Comment: FSI data show that CO and THC are both very good surrogates for total organic HAP. The FSI has a significant amount of THC data, primarily available through annual stack tests. Therefore, for the bagasse boiler subcategory, it is requested that both a CO and a THC standard be set, with the option of complying with either one.

Response: EPA thanks the commenter for their input, but EPA's Office of Research and Development does not support the use of THC as a surrogate for organic HAP from industrial boilers. See preamble for response to comments on how CO limits were modified.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 125

Comment: In this proposal CO is established as a surrogate for organic HAP. Minimizing CO is therefore, intended to demonstrate that organic HAP is minimized. We agree that CO is a good surrogate for organic HAQPs at higher CO levels, but it is clear that the level of organic HAP emissions becomes insensitive to CO concentration below some value, approximately 100 ppm for gas-fired units. Following is a general discussion of the relationship between CO concentration and organic HAP emissions. A specific review of the available data for gas, included as Attachment C, confirms the general discussion and finds that the data in the record indicate that there is no organic HAP benefit to setting a CO limit below 100 ppm.

EPA itself has already reached this conclusion in the Hazardous Waste NESHAP rulemaking, 70 FR 59462 (October 12, 2005):

Most organic hydrocarbons have a lower activation energy (in terms of combustion reactions) and will burn far better at much lower temperatures than CO will. You will see a massive amount of CO (> 500 ppmv) in your stack gases before you typically see significant uncombusted hydrocarbons.

CO is the most common product of incomplete combustion (PIC), and because of its associated chemical kinetics, is one of the most difficult PICs to oxidize completely. As such, CO emissions have historically been used as an indicator of the quality of the combustion process. The concept is that low CO emissions would equate to negligible emissions of other organic compounds. While this is true in general, the mechanisms by which CO is formed and destroyed in the combustion process are different than for other organics. As such, in cases where other organic compounds have been completely oxidized, CO concentrations may still be elevated. While the tendency is to think that further reductions in CO emissions will improve the quality of the combustion, and in turn minimize emissions of other organic compounds, this is not necessarily true. Instead, forcing CO emissions lower and lower ends up over-constraining the combustion process, producing negative impacts on other air quality concerns, without documented improvements in emissions of organics.

Response: See the response to comment EPA-HQ-OAR-2002-0058-2792.1, excerpt 73.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 130

Comment: The use of CO as a surrogate for the reduction of organic compounds is not new, but previous rulemakings have concluded that it is only necessary to reduce CO to less than a particular level to minimize organic HAPs. For example, CO was used as an indicator of combustion efficiency as part of the Interim Status rule for Boilers and Industrial Furnaces (BIFs) that burn hazardous waste. At the time, EPA‘s research demonstrated that BIF units with CO emissions less than 100 ppmvd were achieving the desired destruction efficiency of the organic HAP in the waste streams. As mentioned previously, because the chemical kinetics makes CO far more difficult to oxidize than other organic compounds, it is not necessary to drive CO emissions to zero to obtain a corresponding minimization of organic emissions.

The data used to support the BIF Interim Status rule documented how the selected level of CO corresponded to minimal emissions of the target compounds. That should be the case for Boiler MACT as well. It is not logical to apply the same rules to establish a CO floor, when CO is merely the surrogate. It is more reasonable to collect data that demonstrate low organic emissions, and then to document the corresponding CO emissions for those sources.

API/NPRA agrees that CO is an appropriate surrogate for organic HAP, but believe HAP is minimized at levels well above the 1 or 2 ppm CO proposed. At CO levels below about 100 ppm, differences in organic HAP emissions are negligible.

Recommendation: Where achievable emission limitations for organic HAP that properly reflect source category and unit variability are derivable from representative data, CO should continue to be used as the compliance surrogate for organic HAP. However, the CO limits should reflect the fact that the organic HAP concentration becomes insensitive to CO level below some value (e.g., 100 ppm for gas-fired units).

Recommendation: If any CO emission limits are established for gas-fired units as a surrogate for organic HAP emissions, that limit should be no lower than 100 ppm.

Response: See the response to comment EPA-HQ-OAR-2002-0058-2792.1, excerpt 73.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 131

Comment: There is an additional problem with using CO as a surrogate for organic HAP at very low ppm levels. That is, levels of CO in combustion air going to the boiler or process heater are often higher than the proposed emission limit. Obviously, CO levels up to the CO level in the combustion air can have no relationship to organic HAP generation. It is certainly unreasonable to set a limit for a surrogate that is lower than the monitor would indicate if the equipment were not operating.

The CO National Ambient Air Quality Standard for CO is 9 ppm, 8-hour average and 35 ppm, 1-hour average. EPA reports current ambient levels to be well below these levels in most cases. [Footnote: See Chapter 3 of US EPS, Quantitative Risk and Exposure Assessment for Carbon Monoxide Amended, EPA-452/R-10-009, July 2010; Available at http://www.epa.gov/ttn/naaqs/standards/co/data/CO-REA-Amended-July2010.pdf] However, one hour levels often exceed the 1 and 2 ppm levels in this proposal and, sometimes significantly exceed those levels. Furthermore, vehicle exhaust is identified as the major source of CO and their presence at major sources could cause localized CO levels to exceed the levels in this proposal. In fact, review of EPA‘s 2008 data shows that only 10% of sites monitored have CO concentrations below 1 ppm during the annual second highest 8-hour period. This also means that during startups and shutdowns, when combustion air is passing through the unit uncombusted, at least 90% of units will exceed a 1 ppm emission limit.

While national averages do not reflect micro situations, the following graph shows that even on an 8 hour average basis the annual 2nd maximum 8-hour average on 206 sites is at or above the proposed CO limits. [Footnote: 2008 National Air Trend, CO air quality. http://www.epa.gov/airtrends/carbon.html#conat.]

[See submittal for graph of CO Air Quality, 1990-2008 (Based on Annual 2nd Maximum 8-hour Average) National Trend based on 206 Sites]

Thus, it is clear that levels of CO below about 5 ppm may be due to ambient CO and bear no relationship to organic HAP generation.

Recommendation: Account for ambient CO levels in considering the use of CO as a surrogate for organic HAP generation from boilers and process heaters.

Response: See the Preamble for discussion on how we addressed and revised CO limits.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-2702.1
Comment Excerpt Number: 194

Comment: CO as a surrogate for non-dioxin organics.
EPA chose CO as a surrogate for non-dioxin organic HAP. As EPA recognizes, CO has generally been used as a surrogate for organic HAP because CO is a good indicator of incomplete combustion and organic HAP are products of incomplete combustion. 75 FR 32018. EPA proposes to use emission control methods, including achieving good combustion or using an oxidation catalyst, that both control CO emissions and non-dioxin organic HAP. This correlation, though one step removed from the correlation between PM and HAP metals, is sufficiently strong to support use of CO as a surrogate. EPA need not quantify the correlation or assess the variability because the control technology—good combustion or using an oxidation catalyst—will always reduce some quantum of the non-dioxin organic HAP. Nat'l Lime, 233 F.3d at 639. Given this correlation, EPA is permitted to use CO as a surrogate for specific organic HAP because of the impracticality and cost of establishing emission limits for specific organic HAP. See Sierra Club, 353 F.3d at 986 (reasonable for EPA to use a surrogate "in light of the impracticability of setting individual standards for each metal"); Bluewater Network, 370 F.3d at 18 (use of hydrocarbons as surrogate for PM was reasonable where "direct regulation of PM is more difficult").

EPA's rationales for the use of each of these surrogates are in accord with the facts and the law on this issue. EPA has identified the HAP that it is attempting to regulate. Mossville Envt'l

Action Now v. EPA, 370 F.3d 1232, 1243 (D.C. Cir. 2005) (invalidating use of vinyl chloride as a surrogate where EPA did not identify the HAP for which it was serving as a surrogate). There is no legal barrier to using PM or any criteria pollutant as a surrogate for HAP in this context,. Nat'l Lime Ass'n, 233 F.3d at 638-39. EPA has established that these HAP invariably coexist with the surrogates and will be controlled to some extent by the same technology that controls the surrogate. See Nat'l Lime, 233 F.3d at 639. EPA need not make a numerical estimate of the correlation or discuss its variability. Id. Where alternative surrogates for or methods to control these HAP exist, EPA identified and discussed them. Sierra Club, 353 F.3d at 986. EPA has demonstrated the correlation between the HAP and the surrogates, clearly meeting the standard of reasonableness under National Lime and Sierra Club.

Response: EPA thanks the commenter for their input.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-2702.1
Comment Excerpt Number: 195

Comment: While CIBO agrees that CO is an appropriate surrogate for organic HAP, there are some issues that EPA should address. First, HAP emissions are minimized at levels well above the CO emission standard. In fact, at CO levels below 100 ppm, the differences in organic HAPs emitted are negligible. While high CO levels may imply organic HAP emissions, levels below 100 ppm likely do not have the same proportional level of HAP emissions. EPA should adjust the CO emission standard to reflect that the organic HAP concentration becomes insensitive to CO below certain levels. As discussed in other sections of these comments, forcing CO compliance increases NOx and wastes energy and it is not feasible to have an ultra low NOx burner and CO emissions of 1 ppm. EPA should incorporate a variability concept into the development of the CO standard so regulated sources can actually achieve it and also obtain the HAP reductions desired.

Furthermore, total hydrocarbons (THC) could be used as an alternative standard to CO as a surrogate for non-dioxin organic HAPs. While most hazardous waste incinerator operators will rely on the CO option, some sources may opt to select the THC option as THC CEMS, while more costly, are a workable option. THC levels are often more stable and less reactive to load swings than CO. Since THC is an indicator of non-dioxin organic HAPs (CO is not a HAP whereas much of the THCs are HAPs), there is no reason EPA cannot provide a THC option. Without the THC option, some sources are likely to be faced with a very costly choice: either install a capital intensive CO catalytic reduction system; or remove the most modern and most effective combustion controls for NOx to control CO, and install very expensive post-combustion NOx reduction technologies such as Selective Catalytic Reduction (SCR).

The use of less capital intensive NOx control technologies like Selective Non-Catalytic Reduction (SNCR) on units equipped with SDA's, due to the negative downstream effects of ammonia slip on personnel safety (NH3 release in recycle slurry) and the reliability of downstream components (formation of fouling ammonium salts). Further note that either of these options will significantly increase system draft loss, which will likely require a new ID fan at considerable expense. The enormous capital expense of these options present are not justified, given that such a solution reduces CO but may not actually reduce non-dioxin organic HAPs. This is a classic case of unintended consequences with little commensurate benefit to health or the environment.

Response: EPA thanks the commenter for their input, but EPA's Office of Research and Development does not support the use of THC as a surrogate for organic HAP from industrial boilers. See preamble for response to comments on how CO limits were modified.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 248

Comment: The combustion process converts fuels containing carbon and hydrogen to carbon dioxide and water via a chain of chemical reactions involving fuel components, combustion intermediates and oxidant (usually air). These reactions proceed at different rates depending on temperature and concentrations of species involved. In the furnaces of boilers and process heaters, these
reactions take place within a turbulent mixing process that brings fuel, oxidant, intermediates and products together in varying concentrations and at different temperatures. Equipment designers take great care to design their systems to achieve high combustion efficiency such as providing stable ignition, good fuel-air mixing and sufficient gas residence time at high temperatures within the furnace. Because of practical limitations of these processes in real combustion systems, trace amounts of the reactants and/or combustion intermediates may escape the furnace before the process is completed, resulting in trace amounts of CO, hydrocarbons and/or soot in the exhaust gas. These are undesirable not only because of pollutant implications but also because of fuel costs associated with incomplete conversion of chemical energy in the fuel to combustion products and useful heat or work.
CO and formaldehyde are natural combustion intermediates formed and consumed in flames. Methane (CH_4) is the major component of natural gas and most other gaseous fuels. When methane and air are introduced to the flame, the fuel reacts with oxygen and radical species that exist at high temperatures (O, OH, H) forming simpler hydrocarbons and hydrocarbon fragments such as methyl radical (CH3). CH3 oxidizes to formaldehyde (CH2O). Formaldehyde then converts to formyl radical (HCO), which then dissociates with oxygen to form CO as the last step in the combustion process before being oxidized to CO_2. Its formation late in the combustion process is one reason why CO is a good indicator of combustion efficiency it is formed after the hydrocarbons are consumed and itself is consumed in the coolest and oxygen-depleted portions of the flame. The reaction of CO with oxygen to form CO_2 also is a relatively slow one, making it a worst case indicator, and it is relatively easy to measure. A complete discussion of this subject can be found in any good combustion textbook.

The same hydrocarbon fragments formed as part of the normal combustion process can also be precursors to soot and O-HAPs such as benzene and polycyclic aromatic hydrocarbons (PAH). These are formed via complex pathways in fuel-rich pockets of the flame (e.g., Figures 1 and 2, from Marinov et al.). Most of the compounds formed are subsequently consumed, with only extremely trace amounts - parts per billion to parts per quadrillion surviving the combustion process.

Because CO formation arises from the same hydrocarbon precursors involved with O-HAP formation and its persistence as one of the final, slowest steps in the combustion process, these characteristics make it an ideal indicator of O-HAP emissions.

Response: EPA thanks the commenter for their input.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 249

Comment: CO, total hydrocarbons (THC) and formaldehyde emissions data for gaseous fuels were collected by EPA during the 2008-2009 Boiler MACT Information Collection Request process. These data represent many different types and configurations of boilers, process heaters and metal furnaces. Variations among designs may include heat input capacity, furnace gas temperature and residence time, number and type of individual burners, NOX emission control equipment, operating load and excess O2 during the tests, state of combustion tuning, and others. Although THC is not an O-HAP per se, it may include O-HAPs. Since hydrocarbons are an essential precursor to aldehydes, aromatic and polycyclic O-HAPs, it therefore may be considered a conservative indication of O-HAP potential. The data show that THC and formaldehyde concentrations are consistently at near-zero levels when CO is below 100 ppm (Figure 3).
Above this level, both THC and formaldehyde begin to rise significantly.
To examine the impact of different CO thresholds on THC emissions, the mean THC concentration and 95% confidence intervals were calculated for CO thresholds of 1, 10 and 100 ppm (Figure 4). The THC data for all gas-fired subcategories were grouped together, a total data population of 75 points with CO concentration of 100 ppm and lower. Mean THC emissions are the same (1.6 ppm) for CO thresholds of 1 ppm (54 data points) and 10 ppm (62 data points) and the 95% confidence intervals are approximately the same also. The mean THC concentration (2.7 ppm) is slightly higher at a CO threshold of 100 ppm, and the variability as indicated by the confidence intervals is slightly greater. The overlap of confidence intervals for each threshold shows that the means are not significantly different at the 95% confidence level.
It should be noted that 2 data points with THC concentration far higher than the other data in this region are clearly outliers, seen in Figure 3 for Gas 1 M at CO concentrations of approximately 30 ppm and THC levels of 370-400 ppm. These results are for a natural gas-fired aluminum preheating furnace, and the elevated THC concentrations correspond to test runs performed at

times during the latter part of the batch cycle where the burners operate at very low load. While not unusual for metal furnaces, this operational duty cycle is not typical of most other types of indirect-fired boilers and process heaters; therefore these two data points were excluded from the analysis.

Similarly, the mean formaldehyde concentration and 95% confidence intervals were calculated (Figure 5). The formaldehyde data were aggregated for all gas fuel subcategories as noted above. The mean formaldehyde concentrations are approximately the same, between approximately 0.1 and 0.3 ppm, for CO upper limits from 1 to 100 ppm. Overlap of the confidence intervals indicates that the slight variation in mean formaldehyde concentration is not significant at the 95% confidence level.

Combustion fundamentals indicate that CO should be a conservative surrogate for O-HAP emissions. Pilot scale and previous field test results show that gas combustion within the normal range of operating conditions is expected to produce O-HAP emissions below or near measurement detection limits. At extreme failure mode conditions, elevated emissions of both CO and O-HAPs were evident. The emission test data collected by EPA from a wide variety of boilers, process heaters and metal furnaces clearly show that low CO concentration is consistent with low THC and formaldehyde concentrations. The field data show that THC and formaldehyde emissions insensitive to CO concentrations below approximately 100 ppm. At higher CO levels, THC and formaldehyde also tend to be higher and more variable among different units tested. Data for non-metal furnaces firing both Gas 1 and Gas 2 subcategory fuels are very consistent in this regard.

Response: EPA thanks the commenter for their input, but EPA's Office of Research and Development does not support the use of THC as a surrogate for organic HAP from industrial boilers. See preamble for response to comments on how CO limits were modified.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 250

Comment: The ICR data discussed above includes a wide range of equipment designs and operating conditions. O-HAPs from gas combustion were studied in a collaborative government-industry program in a pilot-scale combustion facility at Sandia National Laboratories in Livermore, California (Seebold, 1997; England et al., 2001). The pilot-scale combustor was configured with a single, up-fired low-NOX gas burner typical of those installed on thousands of indirect-fired process heaters used in petroleum refining and petrochemical production. The burner was a staged combustion design, with “primary” and “secondary” combustion zones. Concentrations of O-HAPs aldehydes, PAH, VOCs were measured for each test condition. A total of 55 different test conditions were evaluated. Tests were conducted over a range of furnace temperatures, fuel compositions and air-fuel settings considered representative of the normal range of full-scale field operating conditions. O-HAP concentrations are generally at or near method detection limits under these conditions (Figure 6).

A series of test under conditions far outside of the normal range also were conducted to evaluate potential failure modes leading to elevated emissions, such as excessive air or fuel in the primary and/or secondary zones, mechanical failure of the burner, and other conditions that would not be encountered in properly operated and maintained field systems but which may occur due to equipment or control failure. O-HAP concentrations are generally similar to those during normal operating conditions, except for cases of extreme air starvation or extreme air quench (Figure 7). Under fuel rich failure modes (total overall stoichiometric ratio, SRt, less than 1), concentrations of aromatic ring compounds (e.g. benzene) and polycyclic hydrocarbons (e.g. PAH) rise sharply. These conditions are also characterized by visible black smoke (smoke spot measurement). This is consistent with the chemistry mechanisms shown in Figures 1 and 2. Under very fuel lean failure modes (excess air 200% and higher), formaldehyde rises sharply accompanied by a modest rise in aromatic and polycyclic compounds. This is consistent with breakdown of the hydrocarbon and CO oxidation chain due to low combustion temperatures and ignition instability.

The relationship between THC and CO during failure mode tests also shows two modes depending on the distribution and range of air-fuel ratios (Figure 8). Elevated THC levels during fuel rich failure modes are also accompanied by very high CO levels. Elevated THC levels during fuel-lean failure modes are accompanied by more modest CO levels. The data suggest different CO intercepts associated with each failure mode. For fuel-rich failure modes, log-log extrapolation of the data to zero THC suggests the onset of THC would occur when CO concentration reaches somewhere in the range of 1000‘s of ppm. For fuel-lean failure modes, the onset of THC formation appears to occur when CO reaches concentrations in the range of 10‘s of ppm.

Aldehydes also show a different relationship with CO depending on failure mode (Figure 9). For fuel-lean failure modes, elevated aldehyde concentrations are accompanied by high CO levels. For fuel-rich failure modes, aldehyde formation is minimal or zero over a wide range of CO. This also is consistent with combustion chemistry fundamentals.

These pilot-scale results illustrate the usefulness of CO as a surrogate indicator for HAP emissions. Elevated HAP emissions are accompanied by elevated CO under fuel-rich and fuel-lean failure modes. However, elevated CO emissions at modest levels do not always produce elevated HAP emissions, suggesting that a modest threshold for CO

Response: EPA thanks the commenter for their input, but EPA's Office of Research and Development does not support the use of THC as a surrogate for organic HAP from industrial boilers. See preamble for response to comments on how CO limits were modified.

Commenter Name: Catharine Fitzsimons
Commenter Affiliation: Iowa Department of Natural Resources
Document Control Number: EPA-HQ-OAR-2002-0058-2767.1
Comment Excerpt Number: 1

Comment: IDNR has the following questions for which it requests that EPA consider and include in its response to comments when finalizing this proposed rule:

1) What test data does EPA have that demonstrates the relationship between CO and non-dioxin organic HAP emissions?
2) If a facility installs add-on emissions controls (e.g. catalytic oxidation), what data does EPA have that shows that there will be a reduction in non-dioxin HAP emissions?
3) In the case of coal-fired boilers, many facilities are installing SO2 controls such as dry scrubbers. These controls can provide some reduction of non-organic HAP emissions. What data does EPA have showing there is still a correlation between CO and non-dioxin organic HAP emissions in these cases?

Response: See the response to comment EPA-HQ-OAR-2002-0058-3187.1, excerpt 15.

Commenter Name: Catharine Fitzsimons
Commenter Affiliation: Iowa Department of Natural Resources
Document Control Number: EPA-HQ-OAR-2002-0058-2767.1
Comment Excerpt Number: 2

Comment: If EPA does not wish to conduct testing to establish this correlation in development of the final Boiler MACT, IDNR recommends that EPA 1) Establish specific standards for specific, organic HAP; 2) Allow the source the option of conducting performance testing for these specific HAP; and 3) Allow the source the option to establish a CO emission level consistent with meeting the standard for the organic HAP.

Response: EPA is not providing alternative compliance options and boilers must meet the applicable CO limits.

Commenter Name: H. Allen Faulkner
Commenter Affiliation: Ascend Performance Materials, LLC
Document Control Number: EPA-HQ-OAR-2002-0058-2743.1
Comment Excerpt Number: 2

Comment: Ascend has a specific comment on item 8d -the CO limit for units designed to burn liquid fuel. The proposed rule has a CO limit of I ppm by volume on a dry basis corrected to 3 percent oxygen. The Decatur site currently operates two process heaters that have a rated heat input capacity of 30 million Btu per hour and would be required to meet this limit based on a 3-run stack sampling,

Ascend requests that EPA reconsider the limit of I ppm. Ascend recognizes that EPA has established this limit as a surrogate for organic HAP emissions and that CO is a good indicator of complete combustion. However, Ascend believes that complete combustion and reductions in organic HAP emissions can be met at much higher CO levels. In fact, EPA reached the same conclusion during the Hazardous Waste NESHAP rulemaking in 2005, where they stated that lowering CO limits below 100 ppmv may not provide significant reductions in organic HAP destruction. Ascend requests that EPA consider modifying the CO limit to a more reasonable concentration, such as 100 ppm CO.

Response: See the preamble for discussion of the revised CO limits.

Commenter Name: Sonnichsen Engineering, LLC
Commenter Affiliation: Tim W. Sonnichsen
Document Control Number: EPA-HQ-OAR-2002-0058-2931.1
Comment Excerpt Number: 3

Comment: The EPA presumes that carbon monoxide (CO) is an appropriate surrogate for other hydrocarbon HAP's. Page 24 of the Area Rule states "A high level of CO is an indicator of incomplete combustion and, thus, a potential indication of elevated organic HAP emissions." The key words in this sentence are "high" and "potential."

If high levels of CO are and indicator of organic HAP's, then the proposed practice of minimizing CO levels to very low levels does not necessarily mean that organic HAP's emissions would be any lower than what would occur at higher CO emission levels. EPA only refers to the potential relationship of CO to organic HAP's. Obviously, there is not a one-to-one correlation of decreasing HAP's with decreasing CO. Would not a more reasonable CO limit based on actual data be preferred rather than the proposed approach of minimizing CO to the maximum level "achievable"?

An example: The State of Wisconsin has for many years imposed a maximum CO level of 500 ppm on industrial-sized wood-fired boilers operating in its state. It has been determined by the state that this CO emission limit will effectively eliminate formaldehyde and other organic HAP's emissions. Would imposing a lower CO limit effectively reduce these emissions? Evidently not according to the State of Wisconsin.

Therefore, imposing absurdly low CO emission levels would likely have no significant benefit to the public by reducing the exposure to organic HAP's while requiring the boiler owner to install expensive and likely unattainable CO emission control requirements

Response: See the response to comment EPA-HQ-OAR-2002-0058-2792.1, excerpt 73.

Commenter Name: Wayne Smith
Commenter Affiliation: Westlake Chemical Corporation
Document Control Number: EPA-HQ-OAR-2002-0058-2785.1

Comment Excerpt Number: 5

Comment: Organic HAP Surrogate: The Proposed Rule relies on Carbon Monoxide emissions as a surrogate for organic HAP emissions. While this may seem to be a logical and simplified approach, there is no testing data or proof that this surrogate is an appropriate approach to establishing a MACT Standard. Further, using the Carbon Monoxide emissions from historical stack test results solely as the data to establish the MACT Floor for Organic HAP emissions is inappropriate.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3187.1, excerpt 15.

Commenter Name: Cathy S. Woollums
Commenter Affiliation: MidAmerican Energy Holdings Company
Document Control Number: EPA-HQ-OAR-2002-0058-2786.1
Comment Excerpt Number: 6

Comment: For this rule, MidAmerican does not support the use of CO as a surrogate for organic HAPs for all affected units and fuel types. MidAmerican concedes EPA's assertion that CO emissions are easier and less expensive to measure and monitor than to measure and monitor emissions of each individual organic HAP, and that they behave similarly as products of poor combustion. However, in this proposed rule, the EPA assumes a 1:1 production and control ratio of CO to organic HAPs; however, there is limited data for certain fuels and size subcategories to demonstrate that there is a strong correlation with CO and organic HAPs at lower limits. The few tests that have been conducted have demonstrated that it is difficult to correlate CO with organic HAPs when CO concentrations fall below 100 parts per million ("ppm"). In this proposed rule, EPA is setting CO emission limits well below 100 ppm. In the case of new and existing gas and liquid units the EPA has set the CO limit at 1 ppm.

Response: See the response to comment EPA-HQ-OAR-2002-0058-2792.1, excerpt 73.

Commenter Name: Marvis A. Lewallen
Commenter Affiliation: Clearwater Paper
Document Control Number: EPA-HQ-OAR-2002-0058-2862
Comment Excerpt Number: 7

Comment: EPA has established CO as the sole surrogate for organic HAPs. However, many of the organic HAPs are not well represented through use of CO as a surrogate. This is particularly true in this industry sector where many boilers are seeking to reduce NOx emissions and so have tuned their boilers such that CO emissions are preferred over NOx. Ironically, this approach has been driven by other EPA mandates. By requiring the use of CO as the surrogate for organic HAPs, EPA would require these sources to alter combustion practices to now increase NOx emissions. In addition, many of the organic HAPs that are derived from biomass are readily destroyed at the high combustion zone and exhaust temperatures typical of biomass boilers. Carbon monoxide, however, has a much higher auto-ignition temperature than the predominant HAPs from biomass. As a result, CO is not a good surrogate across the range of operations typical of a biomass boiler and it is not a good surrogate for the efficacy of any control methods. For all of these reasons, we request that EPA provide alternatives to CO as the basis for HAP control, much as the agency did in the PCWP MACT rulemaking.

Response: See the preamble for discussion of the revised CO limits.

Commenter Name: Cathy S. Woollums
Commenter Affiliation: MidAmerican Energy Holdings Company
Document Control Number: EPA-HQ-OAR-2002-0058-2786.1
Comment Excerpt Number: 7

Comment: Instead of using CO as a surrogate for organic HAPs and establishing very stringent emission limits for both new and existing sources, MidAmerican believes that the most effective and efficient means to control organic HAPs is through the control of the actual combustion process. Both CO and organic HAPs are good indicators of incomplete combustion. Therefore, EPA could promote combustion optimization to reduce organic HAPs. Combustion optimization will be specific to the type of boiler and actual fuel characteristics. Individual facilities should be allowed the flexibility to determine the appropriate level of combustion optimization that will minimize emissions of organic HAPs. Actual combustion optimization could include burner tuning but should not require annual unit outages. The final Boiler MACT should allow facilities to implement actual Work Practice Standards to optimize combustion instead of complying with the proposed stringent CO emission limits. The proposed Work Practice Standards could be expanded to include specific classes of boilers and process heaters with a capacity over 10 million Btu per hour.

Response: See the preamble for discussion on setting MACT standards and how CO limits were modified.

Commenter Name: Jeffrey R.Klieve
Commenter Affiliation: Monsanta Company
Document Control Number: EPA-HQ-OAR-2002-0058-2754.1
Comment Excerpt Number: 9

Comment: Presuming that CO concentration is an indicator parameter for combustion efficiency for organic HAPs present in a fuel stream, these Gas 2 requirements are irrelevant to the control of HAP emissions from Monsanto’s H2 fuel stream. Thus the excessive cost of complying with these requirements is unwarranted.

Response: Subcategory definitions have been revised, see the preamble for discussion.

Commenter Name: Chris M. Hobson
Commenter Affiliation: Southern Company
Document Control Number: EPA-HQ-OAR-2002-0058-2741.1
Comment Excerpt Number: 10

Comment: Carbon monoxide (CO) is a product of incomplete combustion, as are many volatile organic HAPs and semi-volatile organic HAPs. While these chemicals are all products of inefficient combustion, Southern Company does not believe that CO is not an adequate surrogate for organic HAPs, particularly for liquid and solid fuels.

Combustion of fuels for industrial boilers follow the general mixing pattern of many furnaces for combustion, that is, a highly mixed zone of visible flames typically followed by a longer zone of much less mixing. For example, the furnace area of the burner or burners of a typical coal-fired industrial boiler is where the greatest degree of mixing occurs, and is normally followed by a path where the individual burner streams merge and slowly pass through the top sections of the furnace and over convective steam tubes. In reactor engineering terms, industrial combustion can typically be modeled by a constantly-stirred reactor (CSTR) for the burner zone immediately followed by a plug-flow reactor (PFR) for the furnace zone above the burners through the convective section.

For complete combustion, the combustible material that survives the burner zone will have another opportunity to be consumed in the plug-flow zone. Combustion ordinarily requires several things to occur: time for the combustion reaction to complete, high enough temperature to sustain the combustion reactions, enough oxidizer (oxygen, O2, from the combustion air) left over to react with the combustible compounds, and enough mixing to bring the oxidizer and the combustible compounds together.

While it may be true in some circumstances that CO emissions and organic emissions will trend with each other, the differences in the formation and destruction mechanisms during combustion between CO and these other compounds makes CO a very imprecise surrogate. In solid fuel combustion, CO is a major intermediate and thousands of ppm CO are normally found in these flames before being destroyed in the later combustion process. CO is normally formed by the combustion of volatile compounds produced by fuel heating, the combustion of solid char particles, and also by oxidation of soot formed in the flame. Furthermore, the equilibrium between carbon dioxide (CO_2) and CO tends towards more CO as the temperature increases. Therefore, increasing furnace temperatures can produce more CO in the flame just from the chemical equilibrium. Lawn states [Footnote: Principles of Combustion Engineering for Boilers, edited by Lawn, C.J., Academic Press, London, 1987.]

In the presence of excess oxygen the equilibrium concentration of CO at low temperatures is negligible. However, at peak flame temperatures the equilibrium

CO_2 = CO + 0.502

is shifted to favour [sic] CO so that, even under stoichiometric conditions, there is some 3000 vpm of CO in oil firing.

Polycyclic aromatic hydrocarbons (PAH) can be produced and destroyed by a number of mechanisms. These compounds can be formed in secondary devolatilization products in coal, oil, and biomass combustion, but also can then disappear by condensing into soot. PAH can also be formed from the condensation of lighter hydrocarbons in low oxygen regions of the flame. PAH would normally also be destroyed by the combustion of these compounds given enough time, temperature, oxygen, and mixing. The complicated nature of the production and destruction of CO and other hydrocarbons in flames makes the results of experimental tests important in trying to understand the behavior of each.

One important experimental study was conducted by Levendis and Atal from Northeastern University along with Carlson of the U.S. Army [Footnote: Levendis, Y. A., Atal, A., Carlson, J. B., "On the correlation of CO and PAH emissions from the combustion of pulverized coal and waste tires," Environ. Sci. Technol., 32:3767-77 (1998).] These experimenters combusted coal and tire-derived fuel in a well-controlled drop-tube furnace and measured a number of organic emissions as well as CO. They found

At fixed bulk equivalence ratios [excess air levels], however, as the furnace gas temperature increased the PAH yields from both fuels decreased drastically, while the CO yields increased.

They were not able to clearly distinguish why the CO levels increased at the higher furnace temperatures, however. Because furnace temperatures will change with load, with slagging and fouling behavior, with different coals, and even with annual seasons, any correlation between CO and the organic compounds is dependent on always having the same combustion temperature – which is unrealistic. The authors also summarize by saying

Thus, at elevated furnace temperatures, high CO partial pressures may give a false warning on the PAH emissions.

This result is a major reason why Southern Company believes that CO is not a surrogate for the other organic compounds. One or more of the routes of formation and/or destruction of CO versus other organics must act differently when the flame temperature goes up, thus producing more CO emissions but lower organic levels. With such a dramatic difference in emissions resulting from a simple change in temperature, CO is clearly not a good choice for a surrogate for other organic compounds across the spectrum of fuels, boilers, and operating conditions covered by this proposed regulation.

Our recommendation is that a single organic compound, like benzene or toluene, be used as a surrogate, with annual stack testing used for compliance. There are no instruments capable of measuring such low amounts of these compounds continuously in flue gas at present. (Formaldehyde might be a good surrogate as well, but the measurement issues of sampling for formaldehyde in flue gas by manual stack testing methods are so great at present as to make this choice unworkable.)

Response: See the response to comment EPA-HQ-OAR-2002-0058-3187.1, excerpt 15.

Commenter Name: David Foerter
Commenter Affiliation: Institute of Clean Air Companies
Document Control Number: EPA-HQ-OAR-2002-0058-2937.1
Comment Excerpt Number: 30

Comment: Using CO as a surrogate does not assure reduction of organic HAP since the two are not always directly related. Optimizing boiler operation for CO is a convenient method for improving efficiency, but it does not assure any level of HAP reduction. It is preferred that the regulations require testing for total hydrocarbon; this method is no more cumbersome or expensive to conduct on a periodic basis than measuring for CO.

One example of the disconnect between CO and HAP emissions is the impact that most SCR catalysts have on dioxin removal. SCR catalysts can remove 90%+ of dioxins, and this has no relation to the amount of CO in the gas stream or the low level of reduction of CO by the SCR catalyst. Likewise there are base metal (non–PGM) catalysts that will destroy certain types of HAPs without reducing the CO. Synthesis of PCDD/F downstream of the boiler is a recognized source of HAPs in the stack. There is no simple correlation between the CO and the PCDD/F formation.

The preferred method would be to measure total hydrocarbons which can be easily measured using a total hydrocarbon analyzer at periodic intervals. A boiler operator can conduct a THC test just as easily as a CO test. Then a map of the VOC versus CO emissions can be determined for each boiler type and burner configuration. Once the optimum level of HAP is identified, the boiler set points of load and excess O2 can be determined. The boiler operator would simply need to operate the boiler at these operating conditions and demonstrate compliance by maintaining operating records routinely recorded in data capture systems. This is analogous to the already accepted control philosophy for controlling VOC from regenerative thermal oxidizers. The operator must maintain a combustion zone temperature at a prescribed level that provides reasonable assurance of continuous compliance.

Response: EPA thanks the commenter for their input, but EPA's Office of Research and Development does not support the use of THC as a surrogate for organic HAP from industrial boilers. See preamble for response to comments on how CO limits were modified.

Commenter Name: David Foerter
Commenter Affiliation: Institute of Clean Air Companies
Document Control Number: EPA-HQ-OAR-2002-0058-2937.1
Comment Excerpt Number: 31

Comment: Once a boiler operator decides that additional CO control is required, the stack CO level is no longer tied to burner operation, and may not relate to HAP emissions. A burner can be allowed to emit much larger amounts of CO since the catalyst will control it downstream. This could encourage higher CO boiler levels (and higher HAP emissions), negating the intended effect.

Removing CO by means of a catalyst may not result in improved HAP control, which depends on the type of HAP and the temperature at which the catalyst is operated. Most industrial boilers will have a CO catalyst installed at the boiler exit, and that temperature is sufficient to control CO but will not control any organic HAP. CO lights off on a catalyst at much lower temperatures than do most HAP’s, as shown in Table 4. See submittal for table 4 showing that neither Toluene nor Benzene will be controlled at low temperatures. So, once a catalyst is installed, the boiler operator has many ways to operate the boiler that could actually increase HAP.

Response: Regarding the use of oxidation catalysts to reduce organic HAP, there are permits for biomass units through the Florida Department of Environmental Protection which show organic HAP reductions via oxidation catalysts. See information for DEP File No. 0810226-001-AC.

Commenter Name: David Foerter
Commenter Affiliation: Institute of Clean Air Companies
Document Control Number: EPA-HQ-OAR-2002-0058-2937.1
Comment Excerpt Number: 32

Comment: A boiler operator can control organic HAP with the addition of activated carbon used for controlling mercury. However, the CO is not controlled and the boiler operator now must add additional control measures to control CO even though organic HAP is under control. For these reasons it is much more prudent to measure total hydrocarbons directly, rather than relying on a CO measurement.

Response: EPA thanks the commenter for their input, but EPA's Office of Research and Development does not support the use of THC as a surrogate for organic HAP from industrial boilers. See preamble for response to comments on how CO limits were modified.

Commenter Name: David Foerter
Commenter Affiliation: Institute of Clean Air Companies
Document Control Number: EPA-HQ-OAR-2002-0058-2937.1
Comment Excerpt Number: 36

Comment: Direct measurement of total hydrocarbons using the following technologies; catalytic, photo-ionization, infra-red, gas chromatography and flame ionization is possible. ICAC strongly recommends that, as opposed to CO, that Total Hydrocarbons (THC) be measured as the basis for a surrogate for carbon-based HAPS. A number of technologies are available for THC measurements including Flame Ionization Detectors FIDs, Fourier Transform InfraRed, etc.

Response: EPA thanks the commenter for their input, but EPA's Office of Research and Development does not support the use of THC as a surrogate for organic HAP from industrial boilers. See preamble for response to comments on how CO limits were modified.

Commenter Name: Anna Garcia
Commenter Affiliation: Ozone Transport Commission
Document Control Number: EPA-HQ-OAR-2002-0058-2725.1
Comment Excerpt Number: 2

Comment: One provision of the proposed boiler MACT that is of concern in regard to increasing NOx emissions is the use of carbon monoxide (CO) as the surrogate for HAPs. If CO compliance limits for combustion sources are set too low, the result may be increased NOx emissions. One option for an alternative to CO exclusively is to look at boiler efficiency as a surrogate for organic HAPs. The concept here is to use continuous, parametric monitoring of combustion efficiency in addition to CO continuous emission monitors (CEMs) as the control for HAPs.

As an example it may be possible to measure the combustion efficiency for a specific type of boiler firing a specific type of fuel using ASME methods (e.g., Heat-Loss and/or Input-Output boiler efficiency calculations from the ASME test forms) to see if a minimum efficiency standard could be determined for the boiler. That minimum combustion efficiency limit could then be used in addition to using CO limits as a surrogate for good combustion control for HAPs. Some examples of existing boiler efficiency test procedures are referred to in the following documents, which are provided in the submittal of these comments: Cleaver Brooks boiler fact sheet, Partners in Innovation Project document and NISTIR 6913 AHRAE Standard 103-1993.

Response: See the Preamble for discussion of the relationship between CO and Nox and how we addressed and revised CO limits.

Commenter Name: John M. Irving
Commenter Affiliation: Burlington Electric Department
Document Control Number: EPA-HQ-OAR-2002-0058-2954.1
Comment Excerpt Number: 3

Comment: The use of CO as a surrogate for POM does not correlate well with large wood-fired units. We believe that larger wood-fired units have higher operating temperatures and longer residence times, greatly reducing HAPs. CO should not be used as a surrogate for large stoker-fired biomass units.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3187.1, excerpt 15.

Commenter Name: Jeffrey O'Hearn
Commenter Affiliation: Panolam Industries International Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2749.1
Comment Excerpt Number: 3

Comment: 63.7510(c): The use of CO as a surrogate for HAP emissions may not be accurate particularly for sources that are also acting as control devices for other MACT sources. Significant HAP/VOC destruction may be seen, however, the CO levels may not meet the levels as indicated by the “Boiler MACT”. Even with a total VOC destruction efficiency greater than 99%, the CO levels may not meet the levels specific in this standard and by monitoring the CO, would not reflect the actual efficiency of the unit.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3187.1, excerpt 15.

Commenter Name: Richard Krock
Commenter Affiliation: The Vinyl Institute
Document Control Number: EPA-HQ-OAR-2002-0058-2944.1
Comment Excerpt Number: 4

Comment: EPA proposes to use carbon monoxide (CO) emissions as an indicator of the quality of the combustion process on grounds that low CO emissions would equate to negligible emissions of other organic compounds. Although this is true in general, the mechanism by which CO is formed and destroyed in the combustion process differs from other organics, and CO concentrations may remain elevated long after other organic compounds have been completely oxidized depending on the firebox configuration. By forcing lower and lower CO emissions, EPA may over-constrain the combustion process; thereby resulting in the negative impacts on air quality without any measurable improvements in emissions of organic HAPs. EPA should reconsider its categorization, to avoid over-constraining the combustion process with its CO limits.

Response: See the response to comment EPA-HQ-OAR-2002-0058-2792.1, excerpt 73.

Commenter Name: Allyn Ford
Commenter Affiliation: Roseburg Forest Products
Document Control Number: EPA-HQ-OAR-2002-0058-3163
Comment Excerpt Number: 8

Comment: Carbon monoxide is not an appropriate surrogate for organic HAP emissions . While carbon monoxide is a product of incomplete combustion and is an organic compound that can be analyzed and readily measured with CEMS, it is not an appropriate surrogate for organic HAP emissions from biomass combustion. Carbon monoxide has an auto-ignition temperature of almost 1,200°F and manufacturers of thermal oxidizers will tell you that carbon monoxide control efficiency drops off significantly below 1,600°F. Typical organic HAPs from incomplete biomass combustion and their auto-ignition temperatures include: methanol (878°F), formaldehyde (806°F), propionaldehyde (404°F), and acetaldehyde (347°F), all of which are much more easily controlled. The burden to control CO rather than the expected organic HAPs is excessive. A more appropriate surrogate would be total hydrocarbons (THC).

Response: EPA thanks the commenter for their input, but EPA's Office of Research and Development does not support the use of THC as a surrogate for organic HAP from industrial boilers. See preamble for response to comments on how CO limits were modified.

Commenter Name: Catherine W. McCuthen
Commenter Affiliation: Blue Heron Paper Company
Document Control Number: EPA-HQ-OAR-2002-0058-2892.1
Comment Excerpt Number: 9

Comment: EPA has established CO as the sole surrogate for organic HAP. However, many of the organic HAPs are not well represented through use of CO as a surrogate. This is particularly true in this industry sector where many boilers are seeking to reduce NOx emissions and so have tuned their boilers such that CO emissions are preferred over NOx. Ironically, this approach has been driven by other EPA mandates. By requiring the use of CO as the surrogate for organic HAPs, EPA would require these sources to alter combustion practices to now increase NOx emissions. In addition, many of the organic HAPs that are derived from biomass are readily destroyed at the high combustion zone and exhaust temperatures typical of biomass boilers. Carbon monoxide, however, has a much higher auto-ignition temperature than the predominant HAPs from biomass. As a result, CO is not a good surrogate across the range of operations typical of a biomass boiler and it is not a good surrogate for the efficacy of any control methods. For all of these reasons, we request that EPA provide alternatives to CO as the basis for HAP control, much as the agency did in the PCWP MACT rulemaking.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3187.1, excerpt 15 and the preamble for additional discussion on CO limits.

Commenter Name: Allyn Ford
Commenter Affiliation: Roseburg Forest Products
Document Control Number: EPA-HQ-OAR-2002-0058-3163
Comment Excerpt Number: 10

Comment: While it may not be possible to reduce CO emissions sufficiently through combustion controls, it may be possible to adequately reduce organic HAPs through combustion modifications because of their lower ignition temperatures. Roseburg Forest Products believes that facilities should be given the option to demonstrate through testing that their organic HAP emission levels are sufficiently low to protect human health and the environment. An organic HAP emission limit would make more sense than a criteria pollutant emission limit. CO emissions could be measured and correlated to these test results so that a facility-specific CO emission rate can be established at which adequate control of organic HAPs is taking place. If CO emissions are utilized in this way, Roseburg Forest Products believes that CO may be an adequate surrogate for organic HAP emissions.

Response: EPA is not providing an option to determine site-specific limits and must meet the CO limits for a boiler's subcategory.

Commenter Name: Mick Baranko
Commenter Affiliation: Douglas County Forest Products
Document Control Number: EPA-HQ-OAR-2002-0058-2856.1
Comment Excerpt Number: 11

Comment: EPA has established CO as the sole surrogate for organic HAP. However, many of the organic
HAPs are not well represented through use of CO as a surrogate. This is particularly true in this industry sector where many boilers are seeking to reduce NOx emissions and so have tuned their boilers such that CO emissions are preferred over NOx. Ironically, this approach has been driven by other EPA mandates. By requiring the use of CO as the surrogate for organic HAPs, EPA would require these sources to alter combustion practices to now increase NOx emissions. In addition, many of the organic HAPs that are derived from biomass are readily destroyed at the high combustion zone and exhaust temperatures typical of biomass boilers. Carbon monoxide, however, has a much higher auto-ignition temperature than the predominant HAPs from biomass. As a result, CO is not a good surrogate across the range of operations typical of a biomass boiler and it is not a good surrogate for the efficacy of any control methods. For all of these reasons, we request that EPA provide alternatives to CO as the basis for HAP control, much as the agency did in the PCWP MACT rulemaking.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3187.1, excerpt 15 and the preamble for additional discussion on CO limits.

Commenter Name: Roy W. Wood
Commenter Affiliation: Eastman Kodak Company
Document Control Number: EPA-HQ-OAR-2002-0058-2917.1
Comment Excerpt Number: 11

Comment: Coal is a mixture of many different organic compounds that may be HAPs or have the potential to form HAPs if not burned completely. Natural gas is essentially composed of methane, which is not a HAP and has little potential to form HAPs during combustion. Kodak uses NOx reburn in three of its coal-fired boilers to reduce NOx emissions levels. NOx reburn is a technology used to reduce NOx formation by routing the coal-fired combustion gases through a fuel-rich, oxygen-starved, high temperature zone created by substoichiometric natural gas combustion. The NOx is converted to N2 and O2 in the reburn zone. CO is created from the natural gas combustion due to the low oxygen availability. The majority of the CO is converted to CO_2 in the burnout zone created by adding additional oxygen. This technology results in higher CO and substantially lower NOx, but likely does not increase the formation of organic HAPs. Therefore the organic HAP/CO ratio for a NOx reburn source is expected to be substantially lower than for other coal-fired sources. Therefore sources with low HAP/CO ratios should have alternate
compliance options, such as setting a CO level based on passing an organic HAP emissions test or using an alternate surrogate such as total hydrocarbons. The total hydrocarbon approach is used in the hazardous waste incinerator MACT (63.1219(a)(5)).

Response: EPA thanks the commenter for their input, but EPA's Office of Research and Development does not support the use of THC as a surrogate for organic HAP from industrial boilers. See preamble for response to comments on how CO limits were modified.

Commenter Name: Gordon M. Smith
Commenter Affiliation: Mitsubishi Polyester Film, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2912
Comment Excerpt Number: 14

Comment: In this proposal CO is established as a surrogate for organic HAP. Minimizing CO is, therefore, intended to demonstrate that organic HAP is minimized. It appears clear however that the level of organic HAP emissions becomes insensitive to insensitive to CO concentration below some value, approximately 100 ppm for gas-fired units. Following is a general discussion of the relationship between CO concentration and organic HAP emissions. EPA itself has already reached this conclusion in the Hazardous Waste NESHAP rulemaking. As the Agency states at 70 FR 59462 (October 12, 2005):

We explained at proposal why the carbon monoxide standard of 100 ppmv and the hydrocarbon standard of 10 ppmv are appropriate floors. See 69 FR at 21282. The floor level for carbon monoxide of 100 ppmv is a currently enforceable Federal standard. Although some sources are achieving carbon monoxide levels below 100 ppmv, it is not appropriate to establish a lower floor level because carbon monoxide is a conservative surrogate for organic HAP. Organic HAP emissions may or may not be substantial at carbon monoxide levels greater than 100 ppmv, and are extremely low when sources operate under the good combustion conditions required to achieve carbon monoxide levels in the range of zero to 100 ppmv.141 (See also the discussion below regarding the progression of hydrocarbon oxidation to carbon dioxide and water). As such, lowering the carbon monoxide floor below 100 ppmv may not provide significant reductions in organic HAP emissions. Moreover, it would be inappropriate to establish the floor blindly using a mathematical approach—the average emissions for the best performing sources—because the best performing sources may not be able to replicate their emission levels (and other sources may not be able to duplicate those emission levels) using the exact types of good combustion practices they used during the compliance test documented in our data base. This is because there are myriad factors that affect combustion efficiency and, subsequently, carbon monoxide emissions. Extremely low carbon monoxide emissions cannot be assured by controlling only one or two operating parameters.

The use of CO as a surrogate for the reduction of organic compounds is not new, but previous rulemakings have concluded that it is only necessary to reduce CO to less than a particular level to minimize organic HAPs. For example, CO was used as an indicator of combustion efficiency as part of the Interim Status rule for Boilers and Industrial Furnaces (BIFs) that burn hazardous waste. At the time, EPA's research demonstrated that BIF units with CO emissions less than 100 ppmvd were achieving the desired destruction efficiency of the organic HAP in the waste streams. As mentioned previously, because the chemical kinetics make CO far more difficult to oxidize than other organic compounds, it is not necessary to drive CO emissions to zero to obtain a corresponding minimization of organic emissions.

The data used to support the BIF Interim Status rule documented how the selected level of CO corresponded to minimal emissions of the target compounds. That should be the case for Boiler MACT as well. It is not logical to apply the same rules to establish a CO floor, when CO is merely the surrogate. It is more reasonable to collect data that demonstrate low organic emissions, and then to document the corresponding CO emissions for those sources.

Response: See the response to comment EPA-HQ-OAR-2002-0058-2792.1, excerpt 73.

Commenter Name: Sarah E. Amick
Commenter Affiliation: Rubber Manufacturers Association
Document Control Number: EPA-HQ-OAR-2002-0058-2941.1
Comment Excerpt Number: 22

Comment: EPA chose CO as a surrogate for non-dioxin organic HAP. As EPA recognizes, CO has generally been used as a surrogate for organic HAP because CO is a good indicator of incomplete combustion and organic HAP are products of incomplete combustion. 75 Fed.Reg. at 32,018. EPA proposes to use emission control methods, including achieving good combustion or using an oxidation catalyst, that both control CO emissions and non-dioxin organic HAP. This correlation, though one step removed from the correlation between PM and HAP metals, is sufficiently strong to support use of CO as a surrogate. EPA need not quantify the correlation or assess the variability because the control technology—good combustion or using an oxidation catalyst—will always reduce some quantum of the non-dioxin organic HAP. Nat'l Lime, 233 F.3d at 639. Given this correlation, EPA is permitted to use CO as a surrogate for specific organic HAP because of the impracticality and cost of establishing emission limits for specific organic HAP. See Sierra Club, 353 F.3d at 986 (reasonable for EPA to use a surrogate "in light of the impracticability of setting individual standards for each metal"); Bluewater Network, 370 F.3d at 18 (use of hydrocarbons as surrogate for PM was reasonable where "direct regulation of PM is more difficult").

EPA's rationales for the use of each of these surrogates are in accord with the facts and the law on this issue. EPA has identified the HAP that it is attempting to regulate. Mossville Envt'l Action Now v. EPA, 370 F.3d 1232, 1243 (D.C. Cir. 2005) (invalidating use of vinyl chloride as a surrogate where EPA did not identify the HAP for which it was serving as a surrogate). There is no legal barrier to using PM or any criteria pollutant as a surrogate for HAP in this context,.Nat'l Lime Ass'n, 233 F.3d at 638-39.

EPA has established that these HAP invariably coexist with the surrogates and will be controlled to some extent by the same technology that controls the surrogate. See Nat'l Lime, 233 F.3d at 639. EPA need not make a numerical estimate of the correlation or discuss its variability. Id. Where alternative surrogates for or methods to control these HAP exist, EPA identified and discussed them. Sierra Club, 353 F.3d at 986. EPA has demonstrated the correlation between the HAP and the surrogates, clearly meeting the standard of reasonableness under National Lime and Sierra Club.

Response: EPA thanks the commenter for their input.

Commenter Name: Chris Korleski
Commenter Affiliation: Ohio EPA
Document Control Number: EPA-HQ-OAR-2002-0058-2818.1
Comment Excerpt Number: 25

Comment: Organic HAP/Carbon Monoxide Emission Limits:
Ohio EPA understands that lower carbon monoxide emitted from boilers or process heaters theoretically represents more complete combustion and therefore lower organic HAP emissions. However, the proposed CO standards for both coal and gas fired emission sources may be beyond levels representing good combustion. An illustration of this point is that one expects pulverized coal fired boilers to be operating more consistently for efficient combustion while maintaining lower CO levels. Yet, a higher CO emission limit of 90 ppm is proposed for existing pulverized coal fired boilers as compared to the proposed 50 ppm for stoker boilers. Does this higher CO level for pulverized coal boilers indicate that some of the stoker boilers with low CO are merely operating under excessive combustion air levels or with substantial air infiltration? Would these stoker boilers have higher NOx emissions?

In assessing the data for boiler CO emissions, the US EPA should consider this type of balance point. Simply assessing the 12% lowest data points for CO or HAPs may include units that are running with excessive combustion air and at lower overall efficiency thereby increasing emissions of greenhouse gases also. This type of affect probably occurs most often for stoker boilers but is applicable, at a minimum, to all solid fuel fired boilers and likely to the gaseous and liquid fired source categories as well. Therefore, evaluating the emissions database for organic HAP control and the use of CO as a surrogate standard may not be a straight-forward process and may need to consider the quality of operation in defining units representing the top 12% or best operating source.

Response: See preamble for response to comments on how CO limits were modified.

Commenter Name: Chris Korleski
Commenter Affiliation: Ohio EPA
Document Control Number: EPA-HQ-OAR-2002-0058-2818.1
Comment Excerpt Number: 27

Comment: In addressing whether a CO standard is representative of overall low organic HAP emissions for all sources in a source category, the US EPA may want to consider allowing compliance directly with an organic HAP standard. Performance testing could then be used in the case of any specific source to establish CO emission levels consisted with meeting the applicable organic HAP standard.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3187.1, excerpt 15.

Commenter Name: Chris Korleski
Commenter Affiliation: Ohio EPA
Document Control Number: EPA-HQ-OAR-2002-0058-2818.1
Comment Excerpt Number: 31

Comment: The CO emission limit for both existing and new biomass fired boilers appears problematic. The CO emission level supposed to correspond to complete combustion of organic HAPs included dioxins and furans. However, the emission limit of dioxin and furan for fluidized bed and fuel cell boilers is a magnitude higher than for stoker boilers, while the CO limit is lower. Conversely, the CO limit is much higher for suspension burners than stokers, but still have dioxin and furan limits similar to the fluidized bed. This affect could very well be the result of variability or quality of fuels being combusted at the tested sources rather than characteristics of specific boiler types. Once again this points to US EPA better delineating biomass fuels or providing an alternative compliance format for organic HAPs other than the fixed CO emission concentration. As previously suggested, one alternative may be for direct testing of organic HAPs. Another alternative may be to consider setting standards consistent with lower moisture content allowing for better combustion.

Response: EPA revised the subcategories and CO limits for the final rule, see the preamble for discussion.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 52

Comment: Carbon monoxide is the most common product of incomplete combustion (PIC). Because of the associated chemical kinetics, it is one of the most difficult PICs to oxidize completely. CO emissions have historically been used as an indicator of the quality of the combustion process. The concept is that low CO emissions equate to low emissions of other organic compounds. While this is true in general, the mechanisms by which CO is formed and destroyed in the combustion process are different than for other organics. In cases where other organic compounds have been completely oxidized, CO concentrations may still be elevated. While the tendency is to think that further reductions in CO emissions will improve the quality of the combustion, and in turn minimize emissions of other organic compounds, this is not necessarily true. Instead, forcing CO emissions lower and lower ends up over-constraining the combustion process, resulting in other air quality concerns, without achieving corresponding reductions in emissions of organics.

Response: See the response to comment EPA-HQ-OAR-2002-0058-2792.1, excerpt 73.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 56

Comment: The use of CO as a surrogate for the reduction of organic compounds is not new. For example, CO was used as an indicator of combustion efficiency as part of the Interim Status rule for Boilers and Industrial Furnaces (BIFs) that burn hazardous waste. At the time, EPA's research demonstrated that BIF units with CO emissions less than 100 ppmvd were achieving the desired destruction efficiency of the hazardous organics in the waste streams. As mentioned previously, because the chemical kinetics makes CO far more difficult to oxidize than other organic compounds, it is not necessary to drive CO emissions to zero to obtain a corresponding minimization of organic emissions. The American Petroleum Institute's detailed comments to this docket present graphical information that demonstrates the emissions information in EPA's current Boiler MACT database continues to show the same phenomenon - CO emissions decrease rapidly with HAP emissions down to about 100 ppm.

Response: See the response to comment EPA-HQ-OAR-2002-0058-2792.1, excerpt 73.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council

Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 73

Comment: EPA has proposed CO is proposed as a surrogate for organic HAP. Demonstrating a reduction in CO emissions can demonstrate a reduction in organic HAP emissions, but only to the extent that the CO concentration level is around100 ppm. It appears that the level of organic HAP emissions becomes insensitive to CO concentration below 100 ppm.

EPA itself has already reached this conclusion in the Hazardous Waste Combustor NESHAP rulemaking:

The floor level for carbon monoxide of 100 ppmv is a currently enforceable Federal standard. Although some sources are achieving carbon monoxide levels below 100 ppmv,

it is not appropriate to establish a lower floor level because carbon monoxide is a conservative surrogate for organic HAP. Organic HAP emissions may or may not be substantial at carbon monoxide levels greater than 100 ppmv, and are extremely low when sources operate under the good combustion conditions required to achieve carbon monoxide levels in the range of zero to 100 ppmv. . . . As such, lowering the carbon monoxide floor below 100 ppmv may not provide significant reductions in organic HAP emissions. Moreover, it would be inappropriate to establish the floor blindly using a mathematical approach—the average emissions for the best performing sources—because the best performing sources may not be able to replicate their emission levels (and other sources may not be able to duplicate those emission levels) using the exact types of good combustion practices they used during the compliance test documented in our data base.

This is because there are myriad factors that affect combustion efficiency and, subsequently, carbon monoxide emissions. Extremely low carbon monoxide emissions cannot be assured by controlling only one or two operating parameters.

ACC agrees that CO is an appropriate surrogate for organic HAP, but we believe HAP emissions are minimized at levels well above the 1 or 2 ppm CO proposed for Gas 2 and liquid boilers. At CO levels below about 100 ppm, differences in organic HAP emissions are negligible. Where achievable emission limitations for organic HAP that properly reflect source category and unit variability are derived from representative data, CO should continue to be used as the compliance surrogate for organic HAP. However, the CO limits should reflect the fact that the organic HAP concentration becomes insensitive to CO level below some value (e.g., 100 ppm).

Response: Carbon monoxide is often used as an indicator of combustion conditions. Under conditions of ideal combustion, a carbon-based or hydrocarbon fuel will completely oxidize to produce only CO2 and water. Under conditions of incomplete or non-ideal combustion, a greater amount of CO will be formed. With complex carbon-based fuels, combustion is rarely ideal and some CO and concomitant organic compounds are expected to be formed. Because CO and organics are both products of poor combustion, it is logical to expect that limiting the production of CO would also limit the production of organics. As such, EPA is not including other options for compliance with respect to non-dioxin organic HAP; all units must meet CO limits.

Based on comments received there was insufficient data to determine if a lower threshold for CO exists. For example different thresholds were provided (100 vs 500 ppm). In the absence of specific data we computed the CO MACT floors using the data available. Also, since proposal many of the CO limits have increased, see the preamble for further discussion.

Regarding the use of oxidation catalysts to reduce organic HAP, there are permits for biomass units through the Florida Department of Environmental Protection which show organic HAP reductions via oxidation catalysts. See information for DEP File No. 0810226-001-AC.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 74

Comment: Another approach could be to set an alternate total hydrocarbon (THC) standard that sources could meet in lieu of the CO standard (similar to our request for an alternate metals standard that sources would meet in lieu of a PM standard). THC is an appropriate surrogate for organic HAPEPA has collected THC emissions data as part of the Phase I and Phase II ICR, so data to develop alternate THC limits for each subcategory should already be available to the Agency.

Response: EPA thanks the commenter for their input, but EPA's Office of Research and Development does not support the use of THC as a surrogate for organic HAP from industrial boilers. See preamble for response to comments on how CO limits were modified.

Choice of Regulated Pollutants: Dioxin/Furan

Commenter Name: Thomas J. Christofk
Commenter Affiliation: Placer County Air Pollution Control District
Document Control Number: EPA-HQ-OAR-2002-0058-1598.1
Comment Excerpt Number: 10

Comment: PCAPCD objects to the proposed dioxin standards for existing and new major sources, and support setting a single standard for all biomass boiler types. For biomass boilers, the available data has not been shown to demonstrate a correlation between dioxin and CO emissions, thus sub-categorization by boiler type is not warranted. The proposed standard for stoker boilers, which is the most prevalent biomass boiler type, is not reasonably achievable by units that are well operated and maintained and does not adequately consider variability resulting from test method precision. Alternatively, PCAPCD could support a requirement for work practice standards including operation of dry PM collection devices outside of the well established dioxin formation temperature range of approximately 450 – 650 F.

Response: See preamble for final treatment of Dioxin/Furan.

Commenter Name: Christy Sammon
Commenter Affiliation: Southeast Lumber Manufacturers Association
Document Control Number: EPA-HQ-OAR-2002-0058-2727.1
Comment Excerpt Number: 10

Comment: The Agency is not compelled to issue numerical limits for a particular constituent. It can use work practices, or it can conclude that the emissions are insignificant in the context of its duty to address 90% of the designated urban air toxics. For instance, in general, the data for chlorinated dioxins for biomass boilers are non-detect. The Agency could have concluded that the data indicated that numerical limits were not necessary because of the apparently insignificant levels of emissions, however, the Agency proposed unreasonable numerical limits based on the non-detect data. The unreasonableness of the limits is demonstrated by the fact that the proposed chlorinated dioxin limits for some biomass boilers are 100 times lower than the existing limits for hazardous waste incinerators, which should be the most stringently regulated of all combustion devices.

Response: See preamble for final treatment of Dioxin/Furan.

Commenter Name: Thomas Bakk
Commenter Affiliation: State of Minnesota Senate
Document Control Number: EPA-HQ-OAR-2002-0058-2950
Comment Excerpt Number: 11

Comment: A separate specific justification is available to establish a work standard for dioxin/furans rather than MACT emission limits Under section 112(h)(2)(B), EPA may establish a work standard when "the application of measurement methodology to a particular class of sources is not practicable due to technological and economic limitations." Such conditions exist regarding dioxin/furans. The proposed emission limit is so low, and the detection limits for dioxin and furan isomers is so variable that many boilers are likely to exceed the limits even though tests show the isomers are present below detection limits. Therefore, testing for compliance is not technologically practicable. Nor is it economically practicable to incur greater costs that will not resolve the inherent problem of establishing an emission limit that is below the detection limit.

Response: See preamble for final treatment of Dioxin/Furan.

Commenter Name: Sean M. O'Keefe
Commenter Affiliation: Alexander and Baldwin, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-3196
Comment Excerpt Number: 11

Comment: EPA has authority to prescribe a work practice standard for a HAP in lieu of a numerical emissions limit "when the application of measurement technology to a particular class of sources is not practicable due to technological and economic limitations". In the case of the proposed dioxin/furan standards, the standards are so low and the detection limits so variable that emissions testing may be incapable of distinguishing between boilers that are in or out of compliance. Since the proximity of the standard to the detection limit makes emissions testing to determine compliance technologically impracticable, a work practice standard requiring good combustion practices to minimize emissions of dioxins/furans appears well justified. A&B therefore recommends that such a standard be incorporated into the rule in lieu of the proposed numerical emission limits.

Response: See preamble for final treatment of Dioxin/Furan.

Commenter Name: John C. deRuyter
Commenter Affiliation: DuPont
Document Control Number: EPA-HQ-OAR-2002-0058-2793.1
Comment Excerpt Number: 17

Comment: Dioxin/Furan Emissions

EPA has proposed emission limits for dioxin/furan emissions. In many cases, emissions tests indicated emissions below detection levels, and there are very few emissions tests on which to base a standard. While D/F formation and control is fairly well known for MWC units, similar knowledge is not prevalent for conventional fuel firing, as indicated by the limited and questionable data for this rule. There is not enough valid data, and EPA has provided no documentation on the mechanisms of D/F formation in the sources affected by this rule nor of any control technologies known to control these low levels of emissions to the proposed levels. Indeed, combustion equipment and emissions control equipment suppliers in many cases cannot propose equipment and guarantee performance at these levels. Issuing a D/F standard as proposed places the regulated community at a high risk of noncompliance with no certain demonstrated options. This resultant standard is not in keeping with Congressional intent. We believe that in this case at this time, EPA needs to rethink their position and not impose D/F emission limits, but instead focus on a work practice approach based on conventional thinking relative to D/F formation. This is the recommended approach until such time as EPA can gather adequate information and valid emissions data to allow evaluation of actual formation and control methodologies so that a MACT Floor can be established if it is justified.

Response: See preamble for final treatment of Dioxin/Furan.

Commenter Name: David Bonistall
Commenter Affiliation: NewPage Corp
Document Control Number: EPA-HQ-OAR-2002-0058-2920.1
Comment Excerpt Number: 25

Comment: The proposed dioxin/furan emission standards are very low and the detection limits of dioxin and furan isomers are so variable that many boilers are likely to exceed the proposed emission limits for dioxin/furans even though the tests show that all the isomers are present below the detection limits. As a result, EPA has a created a situation of imposing a dioxin/furan emissions limitation even though the method of demonstrating compliance may not reliably distinguish compliant boilers from noncompliant boilers.

Response: See preamble for final treatment of Dioxin/Furan.

Commenter Name: David Bonistall
Commenter Affiliation: NewPage Corp
Document Control Number: EPA-HQ-OAR-2002-0058-2920.1
Comment Excerpt Number: 26

Comment: EPA has ample authority to prescribe a work practice standard instead of a numeric emissions limit. Section 112(h)(2)(B) authorizes EPA to establish work practice standards when "the application of measurement methodology to a particular class of sources is not practicable due to technological and economic limitations." Such is the case for the proposed dioxin/furan standards. The proximity of the standard to the detection limit makes testing for compliance not technologically practicable, while the inability to accurately measure at the level of the proposed standard is economically impracticable because spending more money on the prescribed method will not resolve the inherent problem of setting the standard at the method detection limit. A work practice standard requiring good combustion practices is justified in this situation and would assure that dioxin/furan emissions are minimized.

Response: See preamble for final treatment of Dioxin/Furan.

Commenter Name: David Bonistall
Commenter Affiliation: NewPage Corp
Document Control Number: EPA-HQ-OAR-2002-0058-2920.1
Comment Excerpt Number: 27

Comment: The 112 HAP list includes only the named compounds dibenzofuran (CAS # 132649) and 2,3,7, 8 Tetrachlorodibenzo-p-dioxin (CAS# 1746016) . Therefore, if EPA decides to adopt numeric standards, the standards must be specific to these compounds. EPA has no authority to regulate under § 112 the generic chemical categories of "dioxins" and "furans." In addition, if EPA decides to adopt numerical standards, then EPA must specify in the rule the toxic equivalency factors (TEFs) that should be used to calculate the toxic equivalents (TEQs) for dioxin/furan compounds.

Response: See preamble for final treatment of Dioxin/Furan.

Commenter Name: Chris M. Hobson
Commenter Affiliation: Southern Company
Document Control Number: EPA-HQ-OAR-2002-0058-2741.1
Comment Excerpt Number: 38

Comment: As noted earlier, the achievability of most of the proposed emissions standards is questionable due to a number of flaws in the MACT analysis, particularly the handling of non-detect values. This issue, however, is particularly significant with respect to the dioxin/furan emissions standards because virtually every proposed standard for this HAP is based, in whole or part, on non-detect values. In fact, every reported test run in all floors is less than RMB's estimated practical quantitation limit (PQL) for the test method (0.039 ng/dscfm @ 7% O2). [Footnote: RMB's estimate of PQL for D/F (TEQ PCDD/PCDF) based on as assessment of the reported in-stack detection limits for all subcategories. PQL was estimated based 3 x "MDL", where "MDL" was assumed to be the 95th percentile value of the reported detection limits.] As RMB stated earlier, in such cases where the HAP can not be accurately quantified, it is inappropriate to apply an emissions standard for that HAP. As noted in Section 112(h), the technological limitations of measuring such low pollutant levels suggest that a work practice standard would be more appropriate. Therefore, RMB recommends that EPA specify a work practice standard in place of a numerical emissions standard for D/F.

Response: See preamble for final treatment of Dioxin/Furan.

Commenter Name: Don Grimm
Commenter Affiliation: Hood Industries, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2352
Comment Excerpt Number: 16

Comment: In any event, a work practice standard should be adopted for dioxins/furans.
The proposed dioxin/furan emission standards for biomass boilers are so low and the detection limits of dioxin and furan isomers are so variable that many boilers are likely to exceed the proposed emission limits for dioxin/furans even though the tests show that all the isomers are present below the detection limits. Thus, imposing a dioxin/furan emissions limitation on biomass boilers would be arbitrary and capricious because the method of demonstrating compliance would not reliably distinguish compliant boilers from noncompliant boilers.

In this situation, EPA has ample authority to prescribe a work practice standard instead of a numeric emissions limit. Section 112(h)(2)(B) authorizes EPA to establish work practice standards when “the application of measurement methodology to a particular class of sources is not practicable due to technological and economic limitations.” Such is the case for the proposed dioxin/furan standard for biomass boilers – the proximity of the standard to the detection limit makes testing for compliance not technologically practicable, while the inability to accurately measure at the level of the proposed standard is economically impracticable because spending more money on the prescribed method will not resolve the inherent problem of setting the standard at the method detection limit. A work practice standard requiring good combustion practices is justified in this situation and would assure that dioxin/furan emissions are minimized.

In any event, the 112 HAP list includes only the named compounds dibenzofuran and 1,3,7, 8 TCDD. Therefore, if EPA decides to adopt numeric standards, the standards must be specific to these compounds. EPA has no authority to regulate under 112 the generic chemical categories of “dioxins” and “furans.”

Response: See preamble for final treatment of Dioxin/Furan.

Commenter Name: Randy Thurman and Brent Stevenson
Commenter Affiliation: Arkansas Environmental Federation and Arkansas Forest & Paper Council
Document Control Number: EPA-HQ-OAR-2002-0058-2719.1
Comment Excerpt Number: 4

Comment: As proposed, The Boiler MACT rule requires initial and annual testing for dioxin/furan emissions. Dioxin or furan emissions are commonly expected from use of waste fuels in boilers and heaters. On June 4, 2010, on the same day this MACT rule was proposed, EPA also proposed a redefinition of Solid Waste under RCRA and very stringent rules to limit dioxin and furan emissions from boilers or heaters which utilize solid waste fuels. Those proposed rules will address the dioxin or furan emissions of concern. Significant dioxin or furan emissions are not encountered from boilers or heaters using non-solid waste fuels. There are very few EPA approved laboratories which can complete stack samples analysis for dioxin and furans. The laboratory analysis and the stack testing procedures for dioxin and furan traces are both expensive and time consuming. Again the boilers and heaters using solid waste fuels are proposed to be strictly regulated by the redefinition of solid waste and the air rules specific to those units. It would be unnecessary, inappropriate, and extremely burdensome to require the expensive testing and analysis for dioxin or furan from units using clean non solid waste fuels. The dioxin/furan emission testing requirements for this category of air emission sources should be removed from the final rule.

Response: See preamble for final treatment of Dioxin/Furan.

Commenter Name: Jack Carter
Commenter Affiliation: Weyerhaeuser Company
Document Control Number: EPA-HQ-OAR-2002-0058-2797.1
Comment Excerpt Number: 8

Comment: A somewhat similar issue as that for mercury, trade group analyses show that detection limit issues combined with EPA's chosen MACT floor methodology especially impact biomass units where dioxin formation in the combustion units is not well understood or predictable and its control is even less certain than for mercury.

Response: See preamble for final treatment of Dioxin/Furan.

Commenter Name: Stephen R. Gossett
Commenter Affiliation: Eastman Chemical Company
Document Control Number: EPA-HQ-OAR-2002-0058-3137.1
Comment Excerpt Number: 9

Comment: No numerical emission standard for dioxin/furans (D/Fs) should be established at this time.

EPA has established MACT floor standards for coal-fired boilers for D/Fs from an inadequate dataset and has no sound basis for supporting the assumption that a control technology is available that has been demonstrated to reduce D/Fs from coal-fired boilers exists.

One of Eastman's boilers, Boiler 30 is an excellent example of the dilemma the proposed D/F standard causes. This boiler, a pulverized coal boiler with a spray dryer absorber and ESP was tested in 2009 as part of the Phase II ICR. It is a top performer for PM and HCl and has low CO emissions. Yet, it would fail the proposed D/F standard of 0.003 ng/dscm TEQ with a stack test value of 0.006. This boiler has all the characteristics of a boiler that should have low D/F emissions. There is adequate sulfur content in the coal supply (~1 percent sulfur) to inhibit the formation of D/Fs and it had low chlorine content (~200 ppm) during the stack test. While it did have a low D/F emission rate, it still would not meet the proposed standard. While this may be an artifact of data issues related to detection limits and consistent reporting of the various boilers in EPA's limited dataset, it leaves us with the dilemma of what can possibly be done to meet the standard. Unlike hazardous waste incinerators or municipal waste incinerators, both of which can have much higher D/F emissions than coal-fired boilers, there is no known solution to reduce D/Fs. In the case of hazardous waste incinerators, many of them simply removed waste heat boilers to eliminate most of the D/F formation. In this case, it would be arbitrary and capricious for EPA to set a standard that requires sources to reduce what is already a very low emission rate with no known or demonstrated technologies available to make the reduction.

The EPA has only recently gathered any D/F emissions data from coal-fired boilers and has not yet fully developed an understanding of the variability of D/F emissions over time or an understanding of the cause of D/F emissions in coal-fired boilers. EPA has only one 3-run test from any given boiler from which to establish the MACT floor. The reported emissions of D/F are at extremely low levels very close to detection limits. EPA has not established that these levels are repeatable over time or across variations in fuel by the best-performing units. Any given unit (even the “top performers” identified in the MACT floor support memoranda) is at great peril of failing the D/F emission limit in the annual performance tests. Such a result may well be the result of normal statistical variability which has not been accounted for in EPA’s MACT floor analysis. Also, neither EPA nor the regulated sources have an adequate understanding of how to reduce or control D/F emissions from coal-fired boilers.

Response: See preamble for final treatment of Dioxin/Furan.

Commenter Name: Jack Carter
Commenter Affiliation: Weyerhaeuser Company
Document Control Number: EPA-HQ-OAR-2002-0058-2797.1
Comment Excerpt Number: 13

Comment: A work practice standard should be adopted for dioxins/furans in lieu of the infeasible emission limitations, especially those for biomass boilers. Based on available data for our fleet of major source boilers only one potentially can meet the proposed limitation for its subcategory. As detailed in technical evaluations by NCASI and in the AWC and AF&PA comments, the proposed dioxin/furan emission standards for biomass boilers are so low and the detection limits of dioxin and furan isomers are so variable that many boilers will not be able to meet the proposed emission limits, even when the tests show that all the isomers are present below the detection limits. These results indicate that imposing a dioxin/furan emissions limitation on biomass boilers would be arbitrary and capricious because the method of demonstrating compliance would not reliably distinguish compliant boilers from noncompliant boilers.

In this situation, EPA has the authority to adopt a work practice standard instead of a numeric emissions limit, per CAA 112(h)(2)(B). EPA is authorized to establish work practice standards when “the application of measurement methodology to a particular class of sources is not practicable due to technological and economic limitations.” Since this clearly is the case for biomass boilers, a work practice standard, for example, requiring good combustion practices, is justified and would assure that dioxin/furan emissions are minimized.

Response: See preamble for final treatment of Dioxin/Furan.

Commenter Name: N/A
Commenter Affiliation: Sierra Club, Clean Air Task Force, Earthjustice, and Natural Resources Defense Council
Document Control Number: EPA-HQ-OAR-2002-0058-3187.1
Comment Excerpt Number: 18

Comment: EPA's decision not to regulate dioxin/furan organics through the CO surrogate further belies the problems with its use of a CO surrogate for any organic HAP. Although the Agency properly (and correctly) notes that one basis for setting separate D/F standards is that these organic HAPs are formed differently than the non-D/F organic HAPs, EPA also asserts that somehow it is the "high toxicity associated with even low masses of these compounds," id., justifies setting a MACT standard for these HAPs, rather than relying on the surrogate. But the statute nowhere establishes this framework for standard setting, such that some HAPs should be regulated pollutant by pollutant because of their high toxicities, whereas others can be regulated by surrogates. On the contrary, the default under the statutory language is for the Agency to set MACT emissions standards for all listed HAP, based on the actual performance of the best performing sources, without reference to the relative toxicities of each HAP, or the costs of control or compliance with HAP-specific emissions limits. Further, as EPA is aware, other organic HAPs, including PCBs and POM are also highly toxic even at very low masses.

Response: See preamble for final treatment of Dioxin/Furan.

Commenter Name: Steven M. Maruszewski
Commenter Affiliation: The Pennsylvania State University
Document Control Number: EPA-HQ-OAR-2002-0058-2729.1
Comment Excerpt Number: 19

Comment: Dioxins/Furans (D/F)
The D/F emission limits proposed in this regulation are extremely low and the level of control provided by this regulation were identified on 75 FR 32037 of the Background Document, Section V, Item A. What are the air impacts?
"Emissions of dioxin/furans, on a total mass basis, will be reduced by 722 grams per year for existing units and 1 gram per year for new units. A discussion of the methodology used to estimate emissions and emissions reductions is presented in ``Estimation of Baseline Emissions and Emissions Reductions for Industrial, Commercial, and Institutional Boilers and Process Heaters (2010)'' in the docket.e have reviewed Table 3 – Summary of MACT Floor Results for the Organic HAP Subcategories, (existing units) on page 75 FR 32023 and Table 2 to Subpart DDDDD of Part 63 – Emission Limits for Existing Boilers and Process Heaters and found that 1,837 existing units will be affected by the D/F emission limits and testing requirements. 722 grams of D/F is equal to 1.59 lbs. On a per unit basis, this regulation will control approximately 0.39 gram/yr (0.866 x 10-3 lb/yr). The emission limits have been described as being so low that during the stack test to establish compliance with this regulation, our consultant indicated that the a facility will be attempting to detect "individual molecules" of this material.
Additional comments supplied in Section II. Background Information found on page 75 FR 32011 concerning the health effects of pollutants from ICI boilers indicate the HAP emissions associated with this rule vary from 61% of total HAP emissions are the result of HCl emissions to metals accounting for approximately 6% of total HAP emissions. The background document indicates and we agree that D/F is a probable human carcinogen. However, the EPA's Background Information does indicate:

"We do not know the extent to which the adverse health effects described above occur in the populations surrounding these facilities. However, to the extent the adverse effects do occur, this proposed rule would reduce emissions and subsequent exposures."
It appears this document has not presented EPA's understanding of the threat that D/F emissions from this source category presents to public health.
It is suggested that EPA review the following questions prior to finalizing this rule:
What portions of the annual total D/F emissions are contributed by this source category?
What are the other major sources of D/F throughout the country?
What are the current conditions for D/F exposure throughout the U.S.? Have levels been going down? Have D/F concentrations been changing? If so, by how much?
Could reductions of 722 grams/yr be achieved more effectively by examining other sources of D/F?

Response: See preamble for final treatment of Dioxin/Furan.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 105

Comment: Although we have not performed any quality assurance of the reports of the tests that exceeded the PQL, based on our audit of their data we suspect that some of these data may be erroneous and may have to be revised or deleted from the dataset.

Response: See preamble for final treatment of Dioxin/Furan.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 198

Comment: There have been no studies on the efficacy of emissions controls on dioxin/furan emissions from industrial boilers. EPA should not set a numerical standard for dioxin/furan because there is not enough information to determine the appropriate level for that standard and how sources outside the top performers would be able to achieve it, or even if sources identified as top performers could consistently meet the standards if additional testing was conducted.

Response: See preamble for final treatment of Dioxin/Furan.

Commenter Name: Leonard W. Sandridge

Commenter Affiliation: University of Virginia
Document Control Number: EPA-HQ-OAR-2002-0058-2769.1
Comment Excerpt Number: 6

Comment: Pages 32017 and 32018 of the preamble state “This proposed rule includes numerical emission limits for PM, mercury, HCl, CO and D/F. The selection of numerical emission limits as the format for this proposed rule provides flexibility for the regulated community by allowing a regulated source to choose any control technology or technique to meet the emission limits, rather than requiring each unit to use a prescribed control method that may not be appropriate in each case.” Consistent with that statement, the proposed Major Source Boiler MACT does not specify required technologies for D/F control, rather it specifies an emission limit.

The preamble acknowledges that D/F can be formed outside the combustion unit. Therefore, while metal, PM, and HCl HAPs may be directly linked to feed rate controls, and organic HAPs may be linked to combustion controls and/or proper operation of the air pollution control system, there are no direct links (no specific operating or feed rate parameters) that can be limited to ensure D/F emissions will remain below the regulatory limit.

The following tables summarize the liquid fuel fired sources and stoker coal sources that make up the MACT floor for D/F:

[See submittal for Table of Sources Comprising the MACT Floor Pool for D/F]

Activated carbon injection (ACI) is indicated as an air pollution control technology that has been demonstrated to reduce D/F emissions. None of the sources in the MACT floor use ACI or apparently any other APCD for D/F control.

Considering the lack of a correlation between an operating or feed rate parameter to the D/F emission rate, UVA questions whether it is appropriate to develop a MACT floor emission rate for the liquid subcategory, with 826 sources, using data from only 3 sources or for the coal-stoker subcategory, with 361 sources, using data from only 2 sources. UVA questions whether these sources, which apparently have inherently low D/F emissions because they have no installed APCD to control D/F emissions, are representative of the existing liquid fuel fired and stoker coal boilers and should be used to determine the floor.

Response: See preamble for final treatment of Dioxin/Furan.

Commenter Name: Robert D. Morrison
Commenter Affiliation: Abbott Laboratories
Document Control Number: EPA-HQ-OAR-2002-0058-2764.1
Comment Excerpt Number: 8

Comment: D/F emissions from stoker boilers (and other combustion units) are similarly influenced by a complex and poorly understood interaction of boiler and fuel parameters.

Because of the lack of understanding of the mechanisms for formation and reduction of D/F, it is not possible to design a control system that can be warranted by its designer to meet a specific emission limit. The emissions from the lowest-emitting units identified by the emission testing required by USEPA in 2009 result from a coincidence that cannot be predictably duplicated in other units, either with or without active control. Thus, EPA cannot rely on those units as the basis for emission limits on other units.

Response: See preamble for final treatment of Dioxin/Furan.

Commenter Name: Robert D. Morrison
Commenter Affiliation: Abbott Laboratories
Document Control Number: EPA-HQ-OAR-2002-0058-2764.1
Comment Excerpt Number: 10

Comment: For D/F emissions, there is very little information as to the relationship of operations and emissions. The basis for the proposed MACT floor for D/F from Gas 2, possibly but not necessarily including at least some cases where LFG is burned, is summarized in Table 3 of the preamble (75 FR 32023). The subcategory is believed by USEPA to include 199 units, but only includes D/F emission data from 5 units, and bases the MACT floor on only a single unit. This amounts to little or perhaps no knowledge about combustion of LFG and other Gas 2 gases in order to define MACT. If a unit does not meet the emission limit based on pre-control emissions, then the availability of emission control is problematic. If carbon injection were implemented, a Gas 2unit would need a fabric filter or other particulate control in addition to an injection system in order to preclude unacceptable PM emissions. However, fabric filters for PM control are essentially nonexistent in commercial gas-fired units. Therefore, to an even greater degree than with stoker coal, the mechanisms of dioxin formation and control are not well documented, and no unit could be constructed or modified to use LFG with sufficient confidence to justify the investment.

Response: See preamble for final treatment of Dioxin/Furan.

Commenter Name: David A. Buff
Commenter Affiliation: Golder Associates Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2801.1
Comment Excerpt Number: 14

Comment: FSI opposes setting a dioxin/furan (D/F) limit for bagasse boilers, and strongly urges a work practice standard be set. The proposed D/F emission standards for biomass boilers are so low and the detection limits of dioxin and furan isomers are so variable that many boilers are likely to exceed the proposed emission limits for D/F even though the tests show that all the isomers are present below the detection limits. Thus, imposing a D/F emissions limitation on biomass boilers would be inappropriate because the method of demonstrating compliance would not reliably distinguish compliant boilers from noncompliant boilers.

In this situation, EPA has authority to prescribe a work practice standard instead of a numeric emissions limit. Section 112(h)(2)(B) authorizes EPA to establish work practice standards when "the application of measurement methodology to a particular class of sources is not practicable due to technological and economic limitations." Such is the case for the proposed D/F standard for biomass boilers – the proximity of the standard to the detection limit makes testing for compliance not technologically practicable. The inability to accurately measure at the level of the proposed standard is economically impracticable because spending more money on the prescribed method will not resolve the inherent problem of setting the standard at the method detection limit.

Response: See preamble for final treatment of Dioxin/Furan.

Commenter Name: David A. Buff
Commenter Affiliation: Golder Associates Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2801.1
Comment Excerpt Number: 15

Comment: The §112 HAP list includes only the named compounds dibenzofuran and 1,3,7,8 TCDD. Therefore, if EPA decides to adopt numeric standards, the standards must be specific to these compounds. EPA does not have the authority to regulate under §112 the generic chemical categories of "dioxins" and "furans.

Response: See preamble for final treatment of Dioxin/Furan.

Commenter Name: Randall D. Quintrell
Commenter Affiliation: Georgia Paper and Forest Products Association, GPFPA
Document Control Number: EPA-HQ-OAR-2002-0058-2905
Comment Excerpt Number: 15

Comment: Too few tests were completed during the floor analysis to be statistically valid. For instance, for pulverized coal category, of the 186 boilers listed, there were 10 Dioxin/Furan tests and limits were based on 2 tests. Setting critical standards on such limited data is arbitrary and capricious. The floor must be re-evaluated using valid testing methods and QA/QC prior to setting any compliance limits. The dioxin/furan testing should be dropped from this proposal and the emission limits should be replaced with work place standards, at least until such time as suitable testing methods can be properly validated and the actual emissions adequately evaluated.

Response: See preamble for final treatment of Dioxin/Furan.

Commenter Name: David A. Buff
Commenter Affiliation: Golder Associates Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2801.1
Comment Excerpt Number: 16

Comment: Currently there is no D/F data available for bagasse boilers, and there is little chance to obtain adequate data prior to EPA determining emission limits for the December 2010 final rule. Only a few bagasse boilers are operating during the current off-season, which extends until October, and off-season operation is not representative of crop season operations.

D/F is more a combustion-related HAP, and not a fuel-related HAP (i.e., D/F is not contained in the fuel). Therefore, only combustion data can be used to set a MACT floor. If EPA were to set a D/F limit for bagasse boilers, it would have to rely on combustion data from other biomass-fired boilers, which would not be representative of bagasse boilers (based on the inherent differences in bagasse boilers described previously). If a D/F limit is set in the final rule that is not representative of bagasse boilers, none of the bagasse boilers may be able to meet the new limit, and there may be no recourse except to shut the boilers down.

Response: See preamble for final treatment of Dioxin/Furan.

Commenter Name: David A. Buff
Commenter Affiliation: Golder Associates Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2801.1
Comment Excerpt Number: 17

Comment: We request that a work practice standard be promulgated in bagasse boilers to reduce D/F information. Suggested work practice standards include:

* Maintain compliance with the CO limit

* Implementing good combustion practices (boiler-specific plan)

* Implementing an Operations and Maintenance Plan (boiler-specific plan)

* Maintaining a minimum temperature at the outlet of the PM control device.

These work practices promote good combustion and therefore minimize D/F formation.

Response: See preamble for final treatment of Dioxin/Furan.

Commenter Name: W. Randall Rawson
Commenter Affiliation: American Boiler Manufacturers Association
Document Control Number: EPA-HQ-OAR-2002-0058-2698.1
Comment Excerpt Number: 21

Comment: * ABMA believes that the limits set forth in the Proposed Boiler MACT for D/F are too stringent. According to five differing tests conducted by an ABMA member company while firing biomass, the D/F level being required for biomass at new stoker units - at 0.00005 ng/meter cubed at 7% O2 – is unattainable with any current technology.

* Two tests were conducted at operating wood-fired plants; three were small-scale tests on agricultural residues. In each case the fuel was tested for chlorine in advance and then samples of the flue gas were extracted during combustion per ASTM standards, transported per ASTM standards, and tested for D/F in qualified labs.

* The lowest average emission of dioxins and furans reported in the tests or for which there was data as Toxic Equivalent (TEQ) to 2.3.7.8 Tetra (para) dioxin was 0.170 ng/standard cubic meters at 7% O2. The highest was about 0.6. Even with activated carbon injection, that under ideal conditions can remove up to 99% of D/F (as well as mercury), the new proposed limit could not be reached. Further, we are not aware of any manufacturer that would guarantee meeting the proposed limit with carbon injection, and there are few in the industry who believe that removal rates at that level can be attained consistently.

Response: See preamble for final treatment of Dioxin/Furan.

Commenter Name: David A. Buff
Commenter Affiliation: Golder Associates Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2801.1
Comment Excerpt Number: 28

Comment: It is also proposed that CO or THC is an adequate surrogate for D/F, and a separate D/F standard is not necessary. D/F has been proven to be related to organic HAP formation. Organic HAP is a precursor to D/F formation. Therefore, limiting CO or THC emissions will also limit D/F emissions.

Response: See preamble for final treatment of Dioxin/Furan.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 142

Comment: The proposed dioxin/furan emission standards for are so low and the detection limits of dioxin and furan isomers are so variable that many units are likely to exceed the proposed emission limits for dioxin/furans even though the tests show that all the isomers are present below the detection limits. Thus, imposing dioxin/furan emissions limitations would be arbitrary and capricious because the method of demonstrating compliance would not reliably distinguish compliant units from noncompliant ones.

In this situation, EPA has ample authority to prescribe a work practice standard instead of a numeric emissions limit under section 112(h)(2)(B) of the ACT. A work practice standard requiring good combustion practices is justified in this situation and would assure that dioxin/furan emissions are minimized.

In any event, the 112 HAP list includes only the named compounds "dibenzofurans" and 2, 3, 7, 8 tetrachlorodibenzo-p-dioxin (TCDD). Therefore, if EPA decides to adopt numeric standards, the standards should be specific to these compounds.

Recommendation: A work practice requirement should be adopted for dibenzofurans and 2, 3, 7, 8 TCDD and proposed generic regulations for dioxin/furans should not be finalized.

Response: See preamble for final treatment of Dioxin/Furan.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 145

Comment: As stated elsewhere in these comments, we are concerned with the lack of data collected on dioxin/furan emissions, the quality of the data collected, the lack of understanding of dioxin/furan formation and control, and the establishment of dioxin/furan emission limits at levels that facilities with test results below detection limits, much less than the limit of quantitation, would potentially violate. There have been no studies on the efficacy of emission control on dioxin/furan emissions from gas- or liquid-fired industrial boilers and process heaters at the extremely low, generally undetectable uncontrolled concentrations measured for Gas 1 and Gas 2 fuels in EPA's database. EPA should not set a numerical standard for dioxin/furan because there is not enough information to determine the appropriate level for that standard and how sources outside the top performers would be able to achieve it.

Recommendation: Do not set numerical emission limits for dioxin/furans for gas- or liquid-fired boilers or process heaters since the data are inadequate and it is unclear controls are available to allow compliance.

Response: See preamble for final treatment of Dioxin/Furan.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-2702.1
Comment Excerpt Number: 197

Comment: Numerical dioxins/furans (D/F) are Inappropriate.
The proposed dioxin/furan emission standards are so low and the detection limits of dioxin/furan isomers are so variable that many boilers are likely to exceed the proposed emission limits for dioxins/furans even though the tests show that all the isomers are present below the detection limits for the 17 isomers. Given that the detection limit is used to differentiate between a blank and presence of an analyte, the above outcome is unreasonable and borders on absurdity.

One of Eastman's boilers, Boiler 30 is an excellent example of the dilemma the proposed D/F standard causes. This boiler, a pulverized coal boiler with a spray dryer absorber and ESP was tested in 2009 as part of the Phase II ICR. It is a top performer for PM and HCl and has low CO emissions. Yet, it would fail the proposed D/F standard of 0.003 ng/dscm TEQ with a stack test value of 0.006. This boiler has all the characteristics of a boiler that should have low D/F emissions. There is adequate sulfur content in the coal supply (~1 percent sulfur) to inhibit the formation of D/Fs and it had low chlorine content (~200 ppm) during the stack test. While it did have a low D/F emission rate, it still would not meet the proposed standard. While this may be an artifact of data issues related to detection limits and consistent reporting of the various boilers in EPA's limited dataset, it leaves the company with the dilemma of what can possibly be done to meet the standard.

Unlike hazardous waste incinerators or municipal waste incinerators, both of which can have much higher D/F emissions than coal-fired boilers, there is no known solution to reduce D/Fs. In the case of hazardous waste incinerators, many of them simply removed waste heat boilers to eliminate most of the D/F formation. In this case, it would be arbitrary and capricious for EPA to set a standard that requires sources to reduce what is already a very low emission rate with no known or demonstrated technologies available to make the reduction. Consequently, we recommend that EPA defer any action on this standard until more is known. Alternatively, EPA should replace the proposed numerical standards for dioxins/furans with work practice standards.

Response: See preamble for final treatment of Dioxin/Furan.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 271

Comment: There are no units with activated carbon injection/fabric filter technology. The ICR dioxin/furan data offer no insights into effective control technologies for gas-fired units.

Response: See preamble for final treatment of Dioxin/Furan.

Commenter Name: Mark Calmes
Commenter Affiliation: Archer Daniels Midland Company
Document Control Number: EPA-HQ-OAR-2002-0058-2927.1
Comment Excerpt Number: 7

Comment: The EPA database is too thin and too encumbered with detection limit issues to enable a satisfactory floor to be determined for dioxin/furans. Furthermore, not enough is understood about dioxin formation and control in boilers to evaluate the technical and economic feasibility of control..

Response: See preamble for final treatment of Dioxin/Furan.

Commenter Name: Sonnichsen Engineering, LLC
Commenter Affiliation: Tim W. Sonnichsen
Document Control Number: EPA-HQ-OAR-2002-0058-2931.1
Comment Excerpt Number: 7

Comment: Minimizing Dioxin and Furan Emissions to the MACT standards is “overkill”

My work on waste-to-energy facilities in Poland indicates that the EU has extensively studied the potential harmful effects of Dioxins/Furans. They have set as a standard an emission level of 0.1 ng/m3.

The proposed MACT standards will require Dioxin/Furan control below 0.02 ng/m to 0.0004 ng/m depending on the age and type of biomass source. This is 5 to 250 times lower than the standard established by the EU. Is such a stringent standard really needed?

Understand that no biomass-fired industrial boiler included in your study database was equipped with a “Dioxin/Furan control system.” These are merely the naturally occurring levels of emissions from biomass units that typically have very low levels of chlorine (need to generate Dioxins) and relatively high temperature and time characteristics (needed to burnout Furans). As mentioned above, EPA’s practice of considering low emission levels from a selected boiler population as the result of the alleged “application” of control technologies is ludicrous.

Response: See preamble for final treatment of Dioxin/Furan.

Commenter Name: Edward Bortz
Commenter Affiliation: SP Newsprint Co LLC
Document Control Number: EPA-HQ-OAR-2002-0058-3128
Comment Excerpt Number: 7

Comment: Establish Alternate Standards for Organic HAP

EPA has established CO as the sole surrogate for organic HAP. However, many of the organic HAPs are not well represented through use of CO as a surrogate. This is particularly true in this industry sector where many boilers are seeking to reduce NOx emissions and so have tuned their boilers such that CO emissions are preferred over NOx. Ironically, this approach has been driven by other EPA mandates. By requiring the use of CO as the surrogate for organic HAPs, EPA would require these sources to alter combustion practices to now increase NOx emissions. In addition, many of the organic HAPs that are derived from biomass are readily destroyed at the high combustion zone and exhaust temperatures typical of biomass boilers. Carbon monoxide, however, has a much higher auto-ignition temperature than the predominant HAPs from biomass. As a result, CO is not a good surrogate across the range of operations typical of a biomass boiler and it is not a good surrogate for the efficacy of any control methods. For all of these reasons, we request that EPA provide alternatives to CO as the basis for HAP control, much as the agency did in the PCWP MACT rulemaking.

Response: See preamble for final treatment of Dioxin/Furan.

Commenter Name: Pamela F. Faggert
Commenter Affiliation: Dominion
Document Control Number: EPA-HQ-OAR-2002-0058-2908.1
Comment Excerpt Number: 9

Comment: The very stringent emission standards EPA has proposed for dioxin/furans for all of the source categories were based, in whole or part, on data below detection limits (non-detect values). In such cases where the HAP cannot be accurately quantified, EPA should not apply an emissions standard for that HAP. The technological limitations of measuring such low pollutant levels
suggest that a work practice standard would be more appropriate. Section 112(h)(2)(B) of the CAA authorizes EPA to establish work practice standards when "the application of measurement methodology to a particular class of sources is not practicable due to technological and economic limitations." Therefore, EPA should specify a work practice standard in place of any proposed emissions standard for dioxin/furans. A work practice standard requiring good combustion practices is justified in this situation and would assure that dioxin/furan emissions are minimized.

Response: See preamble for final treatment of Dioxin/Furan.

Commenter Name: Kristine M. Krause
Commenter Affiliation: Wisconsin Electric Power Company, We Energies
Document Control Number: EPA-HQ-OAR-2002-0058-2679.1
Comment Excerpt Number: 9

Comment: The achievability of most of the proposed emissions standards is questionable due to a number of flaws in the MACT analysis, particularly the handling of non-detect values. This issue, however, is particularly significant with respect to the dioxin/furan emissions standards because virtually every proposed standard for this HAP is based, in whole or part, on non-detect values. In such cases where the HAP can not be accurately quantified, it is inappropriate to apply an emissions standard for that HAP. As noted in Section 112(h), the technological limitations of measuring such low pollutant levels suggest that a work practice standard would be more appropriate. Therefore, We Energies recommends that EPA specify a work practice standard in place of a numerical emissions standard for D/F.

Response: See preamble for final treatment of Dioxin/Furan.

Commenter Name: Russell Strader
Commenter Affiliation: Boise Cascade, LLC
Document Control Number: EPA-HQ-OAR-2002-0058-2825
Comment Excerpt Number: 2

Comment: Boise Cascade currently has no data regarding our emissions of dioxin and furans. We will begin collecting that information soon at a cost of $15,000 to $20,000 per stack test. We expect to spend a minimum of $90,000 to $120,000 company-wide just for initial dioxin/furans testing. That cost could easily double or triple if we have to conduct multiple tests to develop confidence in our ability to continuously meet the limit. Because of the expense of testing, and because of the potential variability in the dioxin/furan emissions, Boise Cascade suggests that EPA provide an additional 3 years to comply with this limit. The facility would use the annual stack test data required by the rule to develop confidence in the concentration of these pollutants in the emissions.
EPA could also use this data to consider whether the emission limits for these pollutants were appropriately set.

Response: See preamble for final treatment of Dioxin/Furan.

Commenter Name: Richard Krock
Commenter Affiliation: The Vinyl Institute
Document Control Number: EPA-HQ-OAR-2002-0058-2944.1
Comment Excerpt Number: 3

Comment: VI wishes to express its significant concerns about the quality and sufficiency of data on dioxins and furans, and in particular, the use of detection limit values to set emission limits for these pollutants under this rule. EPA should not set a numerical standard for dioxin/furan because there is not enough information to determine how sources outside the top performers would be able to achieve the standard given the available technology.

Response: See preamble for final treatment of Dioxin/Furan.

Commenter Name: David O'Keefe
Commenter Affiliation: USEC, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-3122
Comment Excerpt Number: 4

Comment: Dioxin/Furan (D/F) emission limits. The D/F emission limits are of questionable value and should be eliminated for several reasons. See "EPA's Reanalysis of Key Issues Related to Dioxin Toxicity and Response to NAS Comments" (EPA/600/R10/038A), 75 FR 28610, etc. Public exposure to D/F has declined: "In fact, as a result of the efforts of EPA, state governments and industry, known and quantifiable industrial emissions of dioxin in the United States have been reduced by more than 90% from 1987 levels" (http://www.fda.gov/Food/FoodSafety/FoodContaminants Adulteration/CheinicalContaminants/DioxinsPCBstucm077524.htin). The original rule did not contain emission limits for D/F, Control of other HAPs such as mercury will provide adequate incidental control and reduction of D/F. The cost of separately monitoring D/F is not warranted taking into consideration the cost of achieving such emission reductions, energy requirements, and environmental impacts as required by Section I12(d)(2) of the CAA. The limited emission data prevents setting an emission limit based on sound science. The coal emission limits were based on only a few units. Neither the initial source category list (EPA-450/3-91-030) or the 2004 final rule identified D/F as a pollutant to be regulated.

Response: See preamble for final treatment of Dioxin/Furan.

Commenter Name: Tracy Smith
Commenter Affiliation: Coastal Forest Products
Document Control Number: EPA-HQ-OAR-2002-0058-2872.1
Comment Excerpt Number: 5

Comment: The Agency is not compelled to issue numerical limits for a particular constituent. It can use work practices, or it can conclude that the emissions are insignificant in the context of its duty to address 90% of the designated urban air toxics. For instance, in general, the data for chlorinated dioxins for biomass boilers are non-detect. The Agency could have concluded that the data indicated that numerical limits were not necessary because of the apparently insignificant levels of emissions, however, the Agency proposed unreasonable numerical limits based on the non-detect data. The unreasonableness of the limits is demonstrated by the fact that the proposed chlorinated dioxin limits for some biomass boilers are 100 times lower than the existing limits for hazardous waste incinerators, which should be the most stringently regulated of all combustion devices.

Response: See preamble for final treatment of Dioxin/Furan.

Commenter Name: Paul J. Allen
Commenter Affiliation: Constellation Energy
Document Control Number: EPA-HQ-OAR-2002-0058-3164
Comment Excerpt Number: 6

Comment: Use Carbon Monoxide (CO) as a surrogate for dioxin. Since this test is so expensive, many biomass plants have not performed this test to determine their emission levels while burning various biomass fuels.

Response: See preamble for final treatment of Dioxin/Furan.

Commenter Name: Douglas J. Van Pelt
Commenter Affiliation: ExxonMobil
Document Control Number: EPA-HQ-OAR-2002-0058-2968.1
Comment Excerpt Number: 7

Comment: With the EPA Method 23, Determination of Polychlorinated Dibenzo-p-dioxins and Polychlorinated Dibenzofurans from Municipal Waste Combustors, a sample is withdrawn isokinetically from the gas stream and collected in the sample probe, on a glass fiber filter, and on a packed column of adsorbent material. The sample cannot be separated into a particle and vapor fraction. The dioxins and furans are extracted from the sample, separated by high resolution gas chromatography (HRGC), and measured by high resolution mass spectrometry (HRMS).

The detection limits for Method 23 are based on the variation in the baseline and have high variability. The detection limit of a measurement is generally defined as the minimum level of an analyte which can be differentiated from an analytical blank. Analytical chemists use Practical Quantitation Limit (PQL) to define the lowest concentration of an analyte which can be quantified at a known level of confidence. A number of different approaches are used for determining the PQL of an analytical method. One approach adopted by EPA in 40 CFR 136, Appendix B is to multiply the detection limit of an analytical method by 3.14 to obtain its PQL.

Using the detection limits provided for each dioxin/furan isomer that yielded non-detects in the EPA's Boiler MACT test runs database, the dioxin/furan analysis PQL values were calculated by applying the multiplier (i.e. 3.14). The table (see submittal for data table) shows the 95th, 75th, and 50th percentile PQL of dioxin/furan measurements as Toxic Equivalency Quantity (TEQs) ng/dscm at 7% O2.

The table shows that for tests achieving the dioxin/furan PQL at the 95th, or 75th, or 50th percentile level, the proposed limit of 0.009 TEQ ng/dscm @7% O2 (for other gas fired boilers and process heaters) is below the PQL. In other words, a facility at which all the dioxin/furan isomers are measured as being below the PQL could be considered to be in violation of the applicable standard. This is clearly unreasonable.

Given the high cost associated with dioxin/furan testing and the extremely low emission levels, which in most cases cannot be quantified or even measured by the currently available methods, we recommend not setting numeric standards but establishing work practice standards for gas fired boilers and process heaters based on good combustion practices.

Response: See preamble for final treatment of Dioxin/Furan.

Commenter Name: Dennis C. McComb
Commenter Affiliation: Lincoln Paper and Tissue
Document Control Number: EPA-HQ-OAR-2002-0058-2999.1
Comment Excerpt Number: 7

Comment: The proposed dioxin/furan emission standards for biomass boilers are so low and the detection limits of dioxin and furan isomers are so variable that many boilers are likely to exceed the proposed emission limits for dioxin/furans even though the tests show that all the isomers are present below the detection limits. Thus, imposing a dioxin/furan emissions limitation on industrial boilers would be arbitrary and capricious because the method of demonstrating compliance would not reliably distinguish compliant boilers from noncompliant boilers.

Response: See preamble for final treatment of Dioxin/Furan.

Commenter Name: William O'Sullivan
Commenter Affiliation: New Jersey Department of Environmental Protection
Document Control Number: EPA-HQ-OAR-2002-0058-2969.1
Comment Excerpt Number: 7

Comment: Testing for dioxins/furans should he limited to sources with a significant potential for
such emissions.

Response: See preamble for final treatment of Dioxin/Furan.

Commenter Name: David P. Tenny
Commenter Affiliation: National Alliance of Forest Owners
Document Control Number: EPA-HQ-OAR-2002-0058-2750.1
Comment Excerpt Number: 8

Comment: The limitations for dioxin/furan are also arbitrary and capricious because these pollutants are not reliably detectable at the proposed regulatory level. As a result, the available methods of demonstrating compliance can not readily distinguish compliant boilers from noncompliant boilers. For example, the ability of tests to detect dioxin/furan at such low levels are so variable, that even boilers that are below the detection levels may still exceed the proposed emissions limitations. In addition, with levels set so low, the risk of sample contamination is extremely high; for example, "one person smoking a cigarette in the vicinity of a test program could contaminate the sample with enough dioxin to put the facility out of compliance." [see submittal for Attachment 1 at 5]. Imposing emissions limitations in this situation would be unreasonable.

Response: See preamble for final treatment of Dioxin/Furan.

Commenter Name: Tim Hagley
Commenter Affiliation: Minnesota Power
Document Control Number: EPA-HQ-OAR-2002-0058-2829.1
Comment Excerpt Number: 8

Comment: A work practice standard should be adopted for dioxins/furans. The proposed dioxin/furan emission standards are so low and the detection limits of dioxin and furan isomers are so variable that many boilers are likely to exceed the proposed emission limits for dioxin/furans even though the tests show that all the isomers are present below the detection limits. In this situation, EPA has ample authority to prescribe a work practice standard instead of a numeric emissions limit.

Response: See preamble for final treatment of Dioxin/Furan.

Commenter Name: Robert Thornton
Commenter Affiliation: International District Energy Association
Document Control Number: EPA-HQ-OAR-2002-0058-2918.1
Comment Excerpt Number: 8

Comment: Another example are the proposed dioxins/furan emission limits for biomass boilers. The detection limits of dioxin/furan isomers are so variable that many boilers are likely to exceed the proposed limits even though the tests will show that all the isomers are present below the detection limits. Consequently, we strongly recommend that sork practice requirements be adopted instead of numeric limits for dioxins/furans in biomass boilers.

Response: See preamble for final treatment of Dioxin/Furan.

Commenter Name: Gary Chandler
Commenter Affiliation: Association of Washington Business
Document Control Number: EPA-HQ-OAR-2002-0058-2914.1
Comment Excerpt Number: 8

Comment: Adopt a work practice standard for dioxins/furans. Many boilers are likely to exceed the proposed emission limits for dioxins/furans due to the stringency of the emissions limit and detection variability. The proposed dioxin/furan emission limit will not reliably distinguish between boilers that are in compliance with the emissions limit and those that are not in compliance.

Response: See preamble for final treatment of Dioxin/Furan.

Commenter Name: Richard L. Killion
Commenter Affiliation: Babcock and Wilcox Power Generation Group
Document Control Number: EPA-HQ-OAR-2002-0058-2722.1
Comment Excerpt Number: 9

Comment: There is minimal industry data or experience that would allow an equipment supplier, such as ourselves, to offer commercial guarantees on the ability to control Dioxins and Furans for the fuels and equipment identified. Most Industry experience in controlling dioxins and furans is for waste-to-energy plants.

Response: See preamble for final treatment of Dioxin/Furan.

Commenter Name: David M. Kiser
Commenter Affiliation: International Paper Company
Document Control Number: EPA-HQ-OAR-2002-0058-2777.1
Comment Excerpt Number: 12

Comment: Proposed dioxin limits appear unachievable or indeterminate at best in whether and how they could be achieved. .

The proposed dioxin/furan emission standards for biomass boilers are so low and the detection limits of dioxin/furan isomers are so variable that many boilers are likely to exceed the proposed emission limits even though the tests show that most isomers are present below the detection limits. The method of demonstrating compliance would not reliably distinguish compliant boilers from noncompliant boilers. International Paper does not know whether we can achieve the proposed dioxin/furan limits or not. Dioxin formation mechanisms, conditions, and locations of formation of these substances are not well understood within boiler designs typical of our industry and very little is known about how we could come into compliance with existing or new control devices. This information is important to characterizing emissions and in designing control systems and/or work practices to control them. There is no technical certainty that the carbon injection systems asserted by EPA as a means of achieving compliance would actually work or if they will work, whether they will meet the proposed limits. The achievability of proposed dioxin limits is indeterminate at best and the ability to be achievable is severely in question thus rendering them unachievable or at least arbitrary and capricious. Therefore, we recommend that the dioxin regulations be eliminated from the rule. If EPA believes dioxin limits would be advisable, then they should undertake the massive research needed to determine mechanisms of formation (within the wide range of existing equipment types) and cost effective means of control.

Response: See preamble for final treatment of Dioxin/Furan.

Commenter Name: David M. Kiser
Commenter Affiliation: International Paper Company
Document Control Number: EPA-HQ-OAR-2002-0058-2777.1
Comment Excerpt Number: 13

Comment: It is possible that existing ESPs, scrubbers and/or spray towers may provide a degree of dioxin control. IP plans to research this issue in the near future and projects it will spend about $750,000 for testing one boiler and two control devices operating with 5 fuel mixes. Although very expensive testing, this will take only a small step in the direction of researching dioxin/furan formation and control in our systems. Nevertheless, it is a first step in a long process and illustrates the tremendous need for research prior to regulating dioxin/furan in industrial boiler processes.

Response: See preamble for final treatment of Dioxin/Furan.

Commenter Name: Tom Midyett
Commenter Affiliation: Tennessee Paper Council
Document Control Number: EPA-HQ-OAR-2002-0058-2691.1
Comment Excerpt Number: 13

Comment: The proposed dioxin/furan emission standards for biomass boilers are so low and the detection limits of dioxin and furan isomers are so variable that many boilers are likely to exceed the proposed emission limits for dioxin/furans even though the tests show that all the isomers are present below the detection limits. Thus, imposing a dioxin/furan emissions limitation on biomass boilers would be arbitrary and capricious because the method of demonstrating compliance would not reliably distinguish compliant boilers from noncompliant boilers.

Response: See preamble for final treatment of Dioxin/Furan.

Commenter Name: Wayne J. Galler and Deborah A. Phillips
Commenter Affiliation: Georgia Industry Environmental Coalition, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2882.1
Comment Excerpt Number: 13

Comment: GIEC urges EPA to adopt work practice standards for dioxin/furans as the detection limits for the various isomers that make up these compounds vary considerably, and as a result, many boilers may end up out of compliance with the MACT standard when the test results actually indicate that all of the isomers are present below the detection limits. Thus, the method of demonstrating compliance would not reliably distinguish compliant boilers from noncompliant boilers. EPA has ample authority to prescribe a work practice standard instead of a numeric emissions limit under Section 112(h)(2)(B) of the CAA which authorizes EPA to establish work practice standards when "the application of measurement methodology to a particular class of sources is not practicable due to technological and economic limitations."

Response: See preamble for final treatment of Dioxin/Furan.

Commenter Name: David M. Kiser
Commenter Affiliation: International Paper Company
Document Control Number: EPA-HQ-OAR-2002-0058-2777.1
Comment Excerpt Number: 14

Comment: Survey of control equipment vendors for design information and for construction quotes indicates that even the manufacturers and installers of control equipment need further research to bring dioxin control to the demonstrated level of controls for other HAPs. Again, this underscores the fact that the data is not there and research needs to commence to provide the support for appropriate rulemaking.

Equipment vendors will not guarantee their equipment can meet the proposed dioxin/furan standards because the research and practical experience just isn’t there yet on which to base a guarantee.

Control equipment vendor guarantees are needed as a basis for making prudent business decisions to invest capital in equipment. Decisions about financing typically depend in part on knowing the equipment will perform the required task – compliance. The achievability of dioxin/furan control in these types of industrial boilers is in the realm of research and not demonstrated science and technology. Absence of availability of guarantees demonstrates this.

Response: See preamble for final treatment of Dioxin/Furan.

Commenter Name: David W. Peightal
Commenter Affiliation: Dakota Gasification Company
Document Control Number: EPA-HQ-OAR-2002-0058-3179
Comment Excerpt Number: 15

Comment: Dioxin/furan should be a work practice and not an emission limit. DGC sees the enforcement of the dioxin/furan standard as "not feasible." In 75 FR 32024 (June 4, 2010), EPA says a standard is "not feasible" when, "the application of measurement technology to a particular class of sources is not practicable due to technological and economic limitations." There is little data and little knowledge available that demonstrates how to control dioxin/furan. An inadequate 2% of affected sources in the liquid subcategory provided test data to EPA to determine the MACT floor.

Response: See preamble for final treatment of Dioxin/Furan.

Commenter Name: David M. Kiser
Commenter Affiliation: International Paper Company
Document Control Number: EPA-HQ-OAR-2002-0058-2777.1
Comment Excerpt Number: 15

Comment: EPA’s emissions test database for dioxin/furan is inadequate to reasonably set MACT limits.

We are concerned with the lack of data collected on dioxin and furan emissions, the quality of the data collected, the lack of understanding of dioxin and furan formation and control, and the establishment of dioxin and furan emission limits at levels that facilities with test results below detection limits would potentially violate. There have been no studies on the efficacy of emissions controls on dioxin and furan emissions from industrial boilers. EPA should not set a numerical standard for dioxins and furans because there is not enough information to determine the appropriate level for that standard and how sources outside the top performers would be able to achieve it, or even if sources identified as top performers could consistently meet the standards if additional testing was conducted.

EPA’s emissions test database for dioxin/furan is inadequate to reasonably set MACT limits. This is confirmed by the lack of data in the database for dioxin/furan in the different subcategories of boilers by which to establish the floor limits. For example in the biomass stoker subcategory, there are 320 units identified as being regulated and only 16 units with dioxin/furan data, which correlates to 5% of the total units. Of available data, only 2 of the sixteen data points were used to set the floor or just 0.6% of the units. For the pulverized coal subcategory, there are 186 units identified and only 10 units with data, or 5% of the subcategory. Only 2 of the sixteen available data points were used to set the floor or 1% of the units. This is totally insufficient data with which to establish dioxin/furan floor limits and these limits should be removed from the final rule as a result. These figures also illustrate that EPA did not appropriately use even the limited emissions data they had available. In as much as all of these units were reportedly selected as "best performing units" in EPA's testing approach and they represent less than 12% of the population of affected units, all these data, not just a small fraction, should be used to set limits.

Response: See preamble for final treatment of Dioxin/Furan.

Commenter Name: Gary Melow
Commenter Affiliation: Michigan Biomass
Document Control Number: EPA-HQ-OAR-2002-0058-2776.1
Comment Excerpt Number: 15

Comment: We request that EPA consider work practice standards in lieu of dioxin/furan limits on biomass boilers. We have data available that indicates that dioxin/furan emissions are minimal. EPA has stated that "combustion control is most effective in reducing dioxin, furan, other organic pollutants, PM, NOx and CO emissions." (Preamble to proposed CISWI rules, 75 FR at 31942.) We believe that the CO emission limitations assure good combustion practices which in turn assure minimal dioxin/furan emissions. Dioxin/furan testing is very expensive. If a dioxin/furan limit is required, then we prefer the TEQ approach, as this has been the means to establish toxicity of the emissions. We do not see added value in
having TEQ and total measures since with the TEQ approach is the most accurate in measuring health effects of the emissions.

Response: See preamble for final treatment of Dioxin/Furan.

Commenter Name: Mark W. Kowlzan
Commenter Affiliation: Packaging Corp. of America
Document Control Number: EPA-HQ-OAR-2002-0058-2913.1
Comment Excerpt Number: 16

Comment: The Agency mandates annual OfF testing. As with mercury and hydrogen chloride, much of the data that is available to EPA shows that the emissions of OIF from industrial boilers are very low - often non-detectable. The high frequency of non-detectible results coupled with variability in method detection limits confound test results such that demonstrating compliance with the proposed standards may be impossible. Work practice standards are more practical and sensible than mandatory testing.

Response: See preamble for final treatment of Dioxin/Furan.

Commenter Name: David M. Kiser
Commenter Affiliation: International Paper Company
Document Control Number: EPA-HQ-OAR-2002-0058-2777.1
Comment Excerpt Number: 19

Comment: A work practice standard for dioxin/furan is more appropriate than an emissions limit, but the value of such a work practice standard is also in question.

For dioxin and furans, we believe there is so much uncertainty in testing methods, in the data, and in what that data means so as to render a standard essentially meaningless, or at least arbitrary and capricious. A work practice standard alternative may hold more value, but this is still uncertain. We understand that some ESP designs can provide conditions favorable for dioxin/furan formation and perhaps a work practice can focus on minimizing these conditions. Beyond that, the details of a work practice standard would also be an appropriate topic for further research.

Response: See preamble for final treatment of Dioxin/Furan.

Commenter Name: Edward E. Quick
Commenter Affiliation: Celanese International Corp
Document Control Number: EPA-HQ-OAR-2002-0058-2840.1
Comment Excerpt Number: 19

Comment: EPA incorrectly states that CO emissions are not a surrogate for D/F.
In the preamble to the proposed regulation, EPA acknowledges that “CO has generally been used as a surrogate for organic HAP because CO is a good indicator of incomplete combustion and organic HAP are products of incomplete combustion.” EPA goes on to state that, “unlike other organic HAP, D/F can be formed outside the combustion unit.” EPA’s assertions contradict science. D/F are formed downstream of the combustion process from organic precursors, such as chlorinated phenols. These precursors are produced by incomplete combustion. Without such precursors, D/F cannot form. Therefore, D/F compounds indirectly form as a result of incomplete combustion. Consequently, any assertion that D/F emissions are not related to incomplete combustion is inaccurate.

Response: See preamble for final treatment of Dioxin/Furan.

Commenter Name: Edward E. Quick

Commenter Affiliation: Celanese International Corp
Document Control Number: EPA-HQ-OAR-2002-0058-2840.1
Comment Excerpt Number: 20

Comment: EPA provides no justification for giving separate consideration to D/F emissions from coal-fired boilers.
Industrial, commercial, and institutional boilers and process heaters are not significant sources of D/F emissions. D/F emissions are significantly higher in combustion units burning chlorinated wastes. For this reason, the Commercial and Industrial Solid Waste Incineration (CISWI) Units rule is the proper venue to address D/F emissions. D/F emission standards are not a valuable component of the proposed rule for industrial, commercial, and institutional boilers and process heaters. EPA does not provide evidence to justify that the health effects of D/F emissions from industrial, commercial, and institutional boilers and process heaters warrant separate consideration. As stated by EPA, the principle organic HAP from coal combustion is benzene. EPA does not adequately make the case that health effects from D/F emissions are significant. It merely states that "The proposed standards establish separate emission limits for D/F because of the high toxicity associated with even low masses of these compounds." Therefore, the use of a surrogate for D/F emissions is justified.

The collection of D/F emissions data is itself inadequate, and most affected sources have no indication of their status of compliance at this time.

Response: See preamble for final treatment of Dioxin/Furan.

Commenter Name: Ted Michaels
Commenter Affiliation: Energy Recovery Council
Document Control Number: EPA-HQ-OAR-2002-0058-2831.1
Comment Excerpt Number: 23

Comment: EPA should promulgate a work practice standard for dioxin/furan emissions from biomass boilers, the same approach it found acceptable for the Gas 1 subcategory.
The proposed dioxin/furan emission standards for biomass boilers are so low and the detection limits of dioxin and furan isomers are so variable that many boilers may be unable to demonstrate compliance even though the tests show that all isomers are present below the detection limits. Imposing a dioxin/furan emissions limitation on biomass boilers would be arbitrary and capricious because the method of demonstrating compliance would not reliably distinguish compliant boilers from noncompliant boilers.

In this situation, EPA has ample authority to prescribe a work practice standard instead of a numeric emissions limit. Section 112(h)(2)(B) authorizes EPA to establish work practice standards when "the application of measurement methodology to a particular class of sources is not practicable due to technological and economic limitations." Such was the case for the Gas1 subcategory where EPA found that instead of prescribing numeric HAP emissions limitations on boilers burning clean gas fuels, EPA proposed to adopt work practices requiring an annual tune up of the boiler. EPA's rationale for establishing work place standards is sound as it recognized that establishing HAP emissions limitations would provide a disincentive for a facility to switch from gas (considered a "clean fuel) to a dirtier but cheaper fuel (i.e. coal). It would be inconsistent with the emissions reductions goals of the CAA, and of Section 112 in particular, to adopt requirements that would result in an overall increase in HAP emissions.

This same rational is applicable to biomass-to-energy facilities which serve a useful waste management purpose, produce renewable energy, and have demonstrated negligible health impacts. In this situation, establishing dioxin/furan standards as proposed will provide a disincentive to manage biomass by a biomass-to energy facility which would be sacrificed in favor of landfilling, a waste management method ranked lower on EPA's solid waste management hierarchy. Severe economic impacts are expected in other industry sectors where biomass boilers are widely used, such as the furniture, sugar, and agricultural products industries. Thus, there is strong economic justification for prescribing work practice standards for biomass boilers in lieu of numeric emissions limitations for dioxin/furan emissions.

Furthermore, the proximity of the dioxin /furan standard to the detection limit makes testing for compliance not technologically practicable, while the inability to accurately measure at the level of the proposed standard is economically impracticable because spending more money on the prescribed method will not resolve the inherent problem of setting the standard at the method detection limit. A work practice standard requiring good combustion practices is justified in this situation and would assure that dioxin/furan emissions will be minimized.

Response: See preamble for final treatment of Dioxin/Furan.

Commenter Name: Ted Michaels
Commenter Affiliation: Energy Recovery Council
Document Control Number: EPA-HQ-OAR-2002-0058-2831.1
Comment Excerpt Number: 24

Comment: EPA's proposal contains emission standards for dioxin/furan as toxic equivalents (TEQ). TEQ emissions are determined from a test for total dioxin/furan where TEQ factors are used to mathematically convert the measured total values to TEQ values. TEQ factors have changed over the years since the original 1989 I-TEQ to the presently used 2005 World Health Organization Toxic Equivalence Factors so setting a TEQ standard represents a potentially moving target. Considering 1) the MACT standards are based on emissions reductions at best performing units and not health effects, 2) TEQ factors are subject to change, EPA should promulgate a single dioxin/furan standard, as total mass.

Response: See preamble for final treatment of Dioxin/Furan.

Commenter Name: Jim Griffin

Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 34

Comment: ACC's view is that the lack of information on dioxin/furan emissions from industrial boilers and information on how to control those emissions requires that EPA set no numerical emission limit for dioxin/furan at this time. However, if EPA proceeds with development of a numerical standard, EPA should (a) establish the 95th percentile detection limit values for the 17 PCDD/F congeners as detection limit values, (b) multiply the detection limit values by 3 or a similar factor to establish the quantitation limit for each of the 17 congeners, (c) reanalyze all of the data by substituting the quantitation limit values for all measurements below the quantitation limit, and (d) set dioxin/furan standards based on these new values and the applicable toxicity equivalents. [see submittal for Table 4 Summary of Detection Limit Statistics for All Non-Detects in the Boiler MACT PCDD/F Data, ng/dscm at 7% O2]

Response: See preamble for final treatment of Dioxin/Furan.

Commenter Name: Kevin M. Dempsey
Commenter Affiliation: American Iron and Steel Institute
Document Control Number: EPA-HQ-OAR-2002-0058-2998.1
Comment Excerpt Number: 34

Comment: In Any Event, a Work Practice Standard Should be Adopted for Dioxins/Furans in Lieu of Emission Standards

The proposed dioxin/furan emission standards are so low and the detection limits of dioxin and furan isomers are so variable that many boilers are likely to exceed the proposed emission limits for dioxin/furans even though the tests show that all the isomers are present below the detection limits. Thus, imposing a dioxin/furan emissions limitation would be arbitrary and capricious because the method of demonstrating compliance would not reliably distinguish compliant boilers from noncompliant boilers.

In this situation, EPA has ample authority to prescribe a work practice standard instead of a numeric emissions limit. Section 112(h) (2) (B) authorizes EPA to establish work practice standards when "the application of measurement methodology to a particular class of sources is not practicable due to technological and economic limitations." Such is the case for the proposed dioxin/furan standards – the proximity of the standard to the detection limit makes testing for compliance not technologically practicable, while the inability to accurately measure at the level of the proposed standard is economically impracticable because spending more money on the prescribed method will not resolve the inherent problem of setting the standard at the method detection limit. A work practice standard requiring good combustion practices is justified in this situation and would assure that dioxin/furan emissions are minimized. In any event, the section 112 HAP list includes only the named compounds dibenzofuran and 1,3,7, 8 TCDD. Therefore, if EPA decides to adopt numeric standards, the standards must be specific to these compounds.

EPA has no authority to regulate under section 112 the generic chemical categories of “dioxins” and “furans.”

Response: See preamble for final treatment of Dioxin/Furan.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 60

Comment: We are concerned with the lack of data collected on dioxin/furan emissions, the quality of the data collected, the lack of understanding of dioxin/furan formation and control, and the establishment of dioxin/furan emission limits at levels that facilities with test results below detection limits violate EPA’s responsibilities under the Clean Air Act. There have been no studies on the efficacy of emissions controls on dioxin/furan emissions from HCI boilers and process heaters. EPA should not set a numerical standard for dioxin/furan because there is not enough information to determine the appropriate level for that standard and how sources outside the top performers would be able to achieve it.

Response: See preamble for final treatment of Dioxin/Furan.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 122

Comment: A WORK PRACTICE STANDARD, RATHER THAN AN EMISSION LIMIT, IS APPROPRIATE FOR DIOXIN/FURAN. The proposed dioxin/furan emission standards are so low and the detection limits of dioxin/furan isomers are so variable that many boilers are likely to exceed the proposed emission limits for dioxins/furans even though the tests show that all the isomers are present below the detection limits for the 17 isomers. Given that the detection limit is used to differentiate between a blank and presence of an analyte, the above outcome is unreasonable. We strongly recommend that EPA replace the proposed numerical standards for dioxins/furans with work practice standards.

Response: See preamble for final treatment of Dioxin/Furan.

Commenter Name: Wayne Brandt
Commenter Affiliation: Minnesota Forest Industries
Document Control Number: EPA-HQ-OAR-2002-0058-3220

Comment Excerpt Number: 11

Comment: A separate specific justification is available to establish a work standard for dioxin/furans rather than MACT emission limits. Under section 112(h)(2)(B), EPA may establish a work standard when "the application of measurement methodology to a particular class of sources is not practicable due to technological and economic limitations." Such conditions exist regarding dioxin/furans. The proposed emission limit is so low, and the detection limits for dioxin and furan isomers is so variable that many boilers are likely to exceed the limits even though tests show the isomers are present below detection limits. Therefore, testing for compliance is not technologically practicable. Nor is it economically practicable to incur greater costs that will not resolve the inherent problem of establishing an emission limit that is below the detection limit.

Response: See preamble for final treatment of Dioxin/Furan.

Choice of Regulated Pollutants: Hg

Commenter Name: Rachel Smolker
Commenter Affiliation: Biofuelwatch
Document Control Number: EPA-HQ-OAR-2002-0058-2805.1
Comment Excerpt Number: 4

Comment: A study published in Science [Friedli, Hans & Radke, Lawrence. Mercury in Smoke from Biomass Fires. (Sep. 2001). Science. Retrieved from http://www.mindfully.org/Air/Mercury-Smoke-Biomass.htm] casts doubt on the reliability of emissions estimates from biomass incineration and suggests that biomass emissions of mercury can be higher than emissions from coal. The study shows a complete release of mercury contained in litter and green vegetation fuel that is different and higher than releases reported for some coal and biomass burning. The study suggests the higher releases of mercury are connected to regional differences in mercury concentrations in vegetation that coincide with the known highest dry/wet deposition rates in the northeastern and northwestern United States.

Response: In the final rule a single floor is established for mercury from all solid fuel units, including both coal/fossil solid and biobased solids. See the preamble for further discussion.

Choice of Regulated Pollutants: PM

Commenter Name: Thomas J. Christofk
Commenter Affiliation: Placer County Air Pollution Control District
Document Control Number: EPA-HQ-OAR-2002-0058-1598.1

Comment Excerpt Number: 3

Comment: PCAPCD supports the use of a PM limit as a surrogate for non-and semi-volatile metal hazardous air pollutants. PM limits and annual source testing are a part of existing Placer County and State of California biomass boiler operating permits.

Response: EPA acknowledges the comment and agrees. It has finalized PM as a surrogate for non-Hg metals in the final rule.

Commenter Name: David Bonistall
Commenter Affiliation: NewPage Corp
Document Control Number: EPA-HQ-OAR-2002-0058-2920.1
Comment Excerpt Number: 3

Comment: NewPage supports the Agency's use of particulate matter (PM) as a surrogate for HAP metals.

Response: EPA acknowledges the comment and agrees. It has finalized PM as a surrogate for non-Hg metals in the final rule.

Commenter Name: Cathy S. Woollums
Commenter Affiliation: MidAmerican Energy Holdings Company
Document Control Number: EPA-HQ-OAR-2002-0058-2786.1
Comment Excerpt Number: 5

Comment: With PM, most, if not all, non-mercury metallic HAPs emitted from combustion sources are PM. Therefore, the same control techniques that would be used to control PM will control non-mercury metallic HAPs.

Response: EPA acknowledges the comment and agrees. It has finalized PM as a surrogate for non-Hg metals in the final rule.

Commenter Name: David Bonistall
Commenter Affiliation: NewPage Corp
Document Control Number: EPA-HQ-OAR-2002-0058-2920.1
Comment Excerpt Number: 8

Comment: NewPage also supports the use of filterable PM for TSM and not PM2.5 for addressing non-mercury metal HAPs. We agree with EPA and the reasons provided in the preamble as to why the use of filterable PM is more appropriate than PM2.5 (e.g. the PM2.5 test method (OTM 27) cannot be used in stacks with entrained water droplets, etc.).

Response: EPA acknowledges the comment and agrees. It has finalized PM as a surrogate for non-Hg metals in the final rule.

Commenter Name: David A. Buff
Commenter Affiliation: Golder Associates
Document Control Number: EPA-HQ-OAR-2002-0058-1841.1
Comment Excerpt Number: 4

Comment: PM is a good surrogate for metals emissions from bagasse boilers, but given the low metals content of bagasse and bagasse ash, an appropriate PM emissions limit for bagasse boilers should be higher than the PM emission limit for other solid fuel boilers.

Response: See the preamble for discussion of a subcategory related to bagasse boilers.

Commenter Name: N/A
Commenter Affiliation: Sierra Club, Clean Air Task Force, Earthjustice, and Natural Resources Defense Council
Document Control Number: EPA-HQ-OAR-2002-0058-3187.1
Comment Excerpt Number: 9

Comment: EPA's Choice of Filterable PM as a Surrogate For Non-mercury Metallic HAPs is Unlawful, Arbitrary, and Capricious.

EPA, in describing the expected reductions in HAP emissions from the its proposed standards, identifies antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, nickel, phosphorus, and selenium as the non-mercury metals emitted by ICIBPH in various amounts. 75 Fed. Reg. 32,010, 32,048. But nowhere else in the preamble to the proposed rule, or in the proposed rule language itself, does the Agency identify which specific listed HAP would be controlled by the limits on PM emissions it proposes. Nor does the Agency state or demonstrate that these HAP "invariably" appear with PM -- EPA simply asserts: "Most, if not all, non-mercury metallic HAP emitted from combustion sources will appear on the flue gas fly-ash. Therefore, the same control techniques that would be used to control the fly-ash PM will control non-mercury metallic HAP." 75 Fed. Reg. at 32,018. EPA does not claim –, and provides no detailed support to show that non-mercury metallic HAPs are "invariably" present in filterable PM, and in fact, they are not.4 See, attached hereto, Exhibit III-1 at 223-224, and Exhibit III-2. Most notably, 50 to 100% of the selenium created by coal-fired boilers exists as a vapor in exhaust gases.5 Similarly, up to 52% of the arsenic also may be present as a gas. Depending upon the fuel and control train, some of the otherwise nonvolatile trace metals, including chromium and nickel, may be present in the vapor phase. Controls on particulate matter will not capture such gaseous HAP emissions.

Nor does the Agency assert, as it must to meet the third prong of the Sierra Club surrogacy test, that PM control techniques are the "only means" by which facilities achieve controls on the non-mercury metallic HAP. Indeed, "[particulate matter] control is not the only means by which facilities 'achieve' reductions in HAP metal emissions." Sierra Club, 354 F.3d at 984. By utilizing less HAP-intensive fuels (even within EPA's proposed sub-categories), plants achieve lower emissions in non-mercury metallic HAP. [Footnote: The effect of fuel-related inputs on metallic HAP emissions differs from such inputs' effect on particulate matter for three reasons. First, the ash content of the coal used as a fuel determines the particulate matter concentration in a plant's flue gases. Exh. III-3. The summary of Powder River coal quality attached as Exh. III-4 shows that the ash content remains stable across many coals, while the trace elements can vary significantly. For example, coal from the Jacobs Ranch mine contains about 5.5% ash and lower concentrations of antimony, arsenic, cadmium, chromium, lead and selenium than coal from the Cordero mine. Thus, lower stack emissions of these elements could be obtained by burning Jacobs Ranch coal instead of Cordero coal. Alternatively, a plant could switch from a coal containing low amounts of HAPs, or to a similar coal containing higher amounts of HAPs, increasing HAP emissions without affecting particulate matter emissions. Such alterations in fuel supply thus "affect HAP metal emissions" in a far different fashion than they affect particulate matter. Sierra Club, 353 F.3d at 985.]

Response: See the response to comment EPA-HQ-OAR-2002-0058-3187.1, excerpt 10.

Commenter Name: N/A
Commenter Affiliation: Sierra Club, Clean Air Task Force, Earthjustice, and Natural Resources Defense Council
Document Control Number: EPA-HQ-OAR-2002-0058-3187.1
Comment Excerpt Number: 10

Comment: While asserting that "non-mercury metallic HAP tend to be on small size particles" (i.e., PM 2.5), EPA instead chose as the surrogate " PM (filterable)" – a larger diameter particle – and regulates simply "PM", defined as "any finely divided solid or liquid material, other than uncombined water...." 75 Fed. Reg. 32,065 (definition in proposed 40 CFR § 63.7575). In effect, PM filterable is chosen as the surrogate for the surrogate for non-mercury metallic HAP. As such, it also should meet the tests for surrogacy, which it does not.

As EPA acknowledges, non-mercury metallic HAPs exist primarily amidst the smallest particulates emitted by boilers (fine particulates, or PM2.5). 75 Fed. Reg. 32,065, and see Exs. III-5 through III-11. Total filterable particulates do not bear the necessary fixed relationship to non-mercury metallic HAP; the amount of non-mercury metallic HAP in total PM will vary, depending upon the balance between large and fine particles amongst those total particulates. A prescribed particulate matter limit can be met by removing larger particles, without removing all of the smaller particles on which the target HAPs are found. Control devices removing filterable particulates do not, in other words, “indiscriminately capture” non-mercury metallic HAPs “along with other particulates.” Indeed, EPA itself has found that a control device may be effective in capturing large particles without having any significant effect on emissions of metallic HAPs. 75 Fed. Reg. 31,896, 31,908 (June 4, 2010)(rejecting control technology that reduces large particles as effective for metallic HAPs because “non-mercury metallic HAP tend to be on small-size particles.”). Although the Agency does note that it based this choice on actual emissions data, showing that “the majority of the filterable PM emitted from units that are well controlled for PM is fine particulate,” this does not amount to a showing that PM2.5 (and non-mercury metallic HAP) is ‘invariably present’ in PM filterable, or that methods for controlling or limiting PM filterable “indiscriminately” capture PM2.5 (and the target HAPs). It could just as easily show that the PM controls at those units capture only larger particles, while allowing the fine particles (and the target HAPs) to escape.

The two most common particulate matter control devices (fabric filter baghouses and electrostatic precipitators) do, in fact discriminate between large particles and the fine particles bearing HAPs. Both tend to have much higher control efficiencies for big particles than small particles. [Footnote: See Exhs. III-1 (Table 1.1-7), III-2 (Fig. 8), and III-12.] Such control devices can as a result, provide low filterable particulate emissions, but high metallic HAP emissions. [Footnote: AP-42, Table 1.1-5; see also Exhs. III-13 (Table 1.1-15) and III-14 (JoAnn S. Lighty, John M. Veranth, and Adel F. Sarofim, Combustion Aerosols: Factors Governing their Size and Composition and Implications to Human Health, 50 J. Air & Waste Mgt. Assoc. 1565, 1582 (2000)).] A fine-meshed baghouse designed to capture PM2.5, in contrast, may produce similar emissions of total particulates to those of an electrostatic precipitator – but the fine-meshed baghouse will produce far lower metallic HAP emissions.

Response: The non-Hg metal HAP are very likely to be present in the particulate phase and will be captured along with the filterable PM in the primary PM control device. The partitioning of the metal HAPs is very complicated and can depend upon the fuel type, the form of the metals in the fuel, other constituents in the fuel and the time-temperature profile of the post-combustion environment. EPA's Office of Research & Development has conducted studies that showed good control of the non-Hg metal HAP followed good control of bulk PM (filterable) across the primary PM control device.

Commenter Name: N/A
Commenter Affiliation: Sierra Club, Clean Air Task Force, Earthjustice, and Natural Resources Defense Council
Document Control Number: EPA-HQ-OAR-2002-0058-3187.1
Comment Excerpt Number: 11

Comment: EPA’s stated reasons for nevertheless selecting filterable particulate matter as its surrogate do not suffice. First, the agency suggests that EPA’s test method for measuring PM2.5 “is not applicable for units equipped with wet scrubbers,” which “likely will be necessary to achieve the proposed HCl emission limits,” whereas filterable particulates are more easily and affordably measured. 75 Fed. Reg. at 32,018. But the agency cannot regulate a “surrogate” that diverges from the target HAPs, however, merely because the surrogate is easily measured.]See Cement Kiln Recycling Coal. v. E.P.A., 255 F.3d 855, 865 (D.C. Cir. 2001) (difficulties in quantifying variation in emissions from units does not justify departure from statutory requirements).] The Clean Air Act requires EPA to prescribe the maximum achievable reduction in hazardous air pollution, 42 U.S.C. § 7412(d)(3); the agency may substitute a surrogate limit only if that substitution results still yields those maximal reductions.

EPA's second reason for selecting filterable particulates is that "the majority of the filterable PM emitted from units that are well controlled for PM is fine-particulate (PM2.5)." 75 Fed. Reg. 32,018. That does not, however, indicate that those units are capturing a proportionate quantity of PM2.5 (or non-mercury metallic HAPs), or that those units are well-controlled for PM2.5 (or non-mercury metallic HAP). As noted above, a pollution-reduction device may achieve large reductions in total filterable particulates, without achieving similar reductions in fine particulates. See Ex. III-12.

EPA's choice of filterable PM as a surrogate for non-mercury metallic HAPs clearly fails the Sierra Club 3-part test for an effective surrogate for those HAPs.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3187.1, excerpt 10.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 93

Comment: AF&PA also supports the use of filterable PM or TSM and not PM2.5 for addressing non-mercury metal HAPs. We agree with EPA and the reasons provided in the preamble as to why the use of filterable PM is more appropriate than PM2.5 (e.g. the PM2.5 test method (OTM 27) cannot be used in stacks with entrained water droplets, etc.). As the purpose of the MACT standards is to limit emissions of HAPs, establishing a PM2.5 emission limit as a surrogate for non-mercury metal HAPs is not appropriate.

Response: EPA acknowledges the comment and agrees. It has finalized PM as a surrogate for non-Hg metals in the final rule.

Commenter Name: Trent A. Dougherty
Commenter Affiliation: Ohio Environmental Council
Document Control Number: EPA-HQ-OAR-2002-0058-2789.1
Comment Excerpt Number: 9

Comment: For example, using PM as a surrogate for non-mercury metallic HAPs is reasonable under ideal fuel sourcing is illegitimate under the current sourcing. It is not beyond the realm of possibility that without sourcing criteria, biomass power generation may use secondary wood sources such as processed wood, and perhaps even construction and demolition debris, which will generate similar levels of particulates as raw wood, but may contain increased concentrations of metals such as arsenic, chromium, lead and additional mercury compared to raw wood fuel stocks. Coupled with an overly narrow and thus less than protective definition of "solid waste," a large portion of these non-mercury metallic HAP emissions could go unmonitored.

Response: See preamble for response on non-hazardous secondary materials. See the Identification of Non-Hazardous Materials That Are Solid Waste for further discussion on classification of secondary materials.

Commenter Name: Chris Greissing
Commenter Affiliation: Industrial Minerals Association
Document Control Number: EPA-HQ-OAR-2002-0058-2740.2
Comment Excerpt Number: 15

Comment: EPA Fails to Support Its Decision to Use PM as a Surrogate. In the Proposed Rule, EPA elected to use particulate matter ("PM") as a surrogate for the emissions of non-mercury metallic HAPs from industrial boilers and process heaters. However, as EPA acknowledges, metallic HAP emissions can vary by fuel type. 75 Fed. Reg. 32018. Given this variability, using the low, single PM limit for all coal-fired boilers of 0.02 lb/MMBTU is not justified. The fact that most fuels "generally emit PM that includes some amount and combination of metallic HAPs" (75 Fed. Reg. 32018, emphasis added), does not establish a reasonable correlation between metallic HAPs and PM emissions, and in the absence of such a correlation the use of a surrogate is not justified.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3187.1, excerpt 10.

Commenter Name: David A. Buff
Commenter Affiliation: Golder Associates Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2801.1
Comment Excerpt Number: 25

Comment: Emission limits for individual metal HAPs (or total selected metals) should be provided as an option in the rule. For boilers burning fuels which are naturally low in metal HAP content, PM control may not be necessary to adequately control HAP emissions, and the requirement to limit PM emissions may unduly burden sources with costly control devices and monitoring equipment. Sources should have the option to meet either a total selected metals limit or a PM limit.

Response: See the response to comment EPA-HQ-OAR-2002-0058-2941.1, excerpt 23.

Commenter Name: David A. Buff
Commenter Affiliation: Golder Associates Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2801.1
Comment Excerpt Number: 30

Comment: FSI agrees with EPA that all fuels do not emit the same type and amount of metallic HAP. This in fact is why PM should not be used as a surrogate for metallic HAP: it would require all sources to meet the same PM limit, regardless of how much metallic HAP is in the fuel or is emitted. This "one limit fits all" approach will impose unnecessary control and compliance costs on sources that have low metallic HAP emissions.

Metallic HAP emissions are a function of the amount of metallic HAP in the fuel, and not total PM emissions. Total PM emissions are more related to unburned carbon and ash in the fuel. The amount of metallic HAP exiting the boiler, regardless of design, will mainly be a function of the metallic HAP content of the fuel since metallic HAP is not converted or transformed in the boiler, but instead exits the boiler as PM. This is illustrated from FSI bagasse boiler data. Bagasse boilers with much less efficient PM controls and much higher PM emissions (wet scrubber control) are shown to have lower metallic HAP emissions compared to better controlled, lower emitting boilers (ESP control).

Response: See the response to comment EPA-HQ-OAR-2002-0058-3187.1, excerpt 10.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-2702.1
Comment Excerpt Number: 192

Comment: A. PM as a surrogate for non-mercury metallic HAP.
EPA chose PM as a surrogate for non-mercury metallic HAP because "[m]ost, if not all, non-mercury metallic HAP emitted from combustion sources will appear on the flue gas fly-ash. Therefore, the same control techniques that would be used to control the fly-ash PM will control non-mercury metallic HAP." Id. In addition, EPA recognizes that using PM as a surrogate will eliminate costly performance testing to comply with multiple individual standards. Id. These reasons are sufficient to sustain use of PM as a surrogate for non-mercury metallic HAP.). In National Lime, the D.C. Circuit held that as long as EPA demonstrates that there is a correlation between the HAP controlled (in that case, metals) and the surrogate (in that case, PM), "it need not quantify that correlation or assess its variability because PM control technology is such that each unit of PM emissions avoided 'carries' within it some quantum of HAP metals." Nat'l Lime Ass'n, 233 F.3d at 639. Furthermore, EPA acknowledges that most sources generally emit PM that includes some amount and combination of metallic HAP. See Bluewater Network v. EPA, 370 F.3d 1, 18 (D.C. Cir. 2004) (upholding EPA's use of hydrocarbons as a surrogate for PM

because, in part, HC contributes to PM pollution). As the D.C. Circuit has recognized, "[i]f HAP metals are invariably present in [source] PM, then even if the ratio of metals to PM is small and variable, or simply unknown, PM is a reasonable surrogate for the metals," assuming that PM control technology indiscriminately captures HAP metals, which is true here, and that there is no independent method of controlling the HAP which did not control for PM as well, which is also true here. Id.; see also Sierra Club v. EPA, 353 F.3d 976, 985 (D.C. Cir. 2004) (applying Nat'l Lime's "three-part analysis" of invariable presence, indiscriminate capture and sole method of control to uphold use of PM as a surrogate for HAP).

EPA's decision to use PM (filterable) rather than PM2.5 is also reasonable because sources with wet scrubbers cannot measure PM2.5, making the surrogate more broadly applicable. In addition, the majority of the filterable PM emitted from units that are well-controlled for PM is PM2.5. See 75 FR 32018. This conclusion is supported by emission data obtained from units not equipped with wet scrubbers during EPA's information collection effort, and so EPA's use of PM (filterable) is reasonable.

Response: EPA acknowledges the comment and agrees. It has finalized PM as a surrogate for non-Hg metals in the final rule.

Commenter Name: David W. Peightal
Commenter Affiliation: Dakota Gasification Company
Document Control Number: EPA-HQ-OAR-2002-0058-3179
Comment Excerpt Number: 1

Comment: The Great Plains Synfuels Plant operates boilers that have a Flue Gas Desulfurization Unit to control SO2 emissions. This control technology is considered BACT and works by using ammonia to scrub the SO2 from the flue gas forming ammonium sulfate, which is used as a fertilizer. One of the natural functions of this FGD system is the slippage of small amounts of ammonia. This ammonia can combine with remaining low level sulfur in the flue gas to form ammonium sulfate in the atmosphere even after it passes through our Wet Electrostatic Precipitator (WESP). DGC should be considered an exception to the logic described in 75 FR 32018 (June 4, 2010) that suggests using total particulate as a surrogate for total HAPs. DGC operates an FGD where a significant amount of ammonium sulfate particulate is produced and eventually emitted from the stack and is not directly related to any HAP emissions. For this reason, PM is not a representative surrogate for HAP for DGC. The WESP works well enough to control emissions so that our most recent stack test shows only 27 lbs/hr of PM10. DGC should not be penalized for having particulate emissions that are not HAPs.

This standard does not seem practical, representative, and needs to be re-evaluated. DGC endorses the comment made by the American Chemistry Council to allow for an alternative compliance method such as a Total Selected Metals (TSM) test which would allow a facility to stack test for certain selected metals in order to demonstrate compliance with appropriate limits. TSM is an option that would provide flexibility to affected sources as an alternative to installing continuous PM monitoring.

Response: See the response to comment EPA-HQ-OAR-2002-0058-2941.1, excerpt 23.

Commenter Name: Brad James
Commenter Affiliation: Trinity Consultants
Document Control Number: EPA-HQ-OAR-2002-0058-2853.1
Comment Excerpt Number: 2

Comment: Using PM as a surrogate will result in overregulation of bagasse boilers, even though the amount of non-mercury metallic HAPs in bagasse boiler emissions varies directly with the amount of PM. This is true for two reasons. First, for the same quantity of PM, there is a lower amount of non-mercury metallic HAPs in bagasse emissions than in other biomass fuels' emissions. This difference arises from the fact that there is a lower concentration of non-mercury metals in bagasse than in other biomass fuels. Second, bagasse boilers release higher amounts of PM than other biomass boilers. This too is due to properties in bagasse itself. Bagasse's higher moisture content and lower density causes a relatively less complete burn than is achieved with drier, denser biomass fuels, which in turn increases the relative amount of PM in bagasse emissions.

Thus, there is more, but less harmful, PM in bagasse emissions than in other biomass emissions, making PM an inappropriate surrogate in the current biomass subcategories. See Sierra Club v. EPA, 353 F.3d 976, 985 (D.C. Cir. 2004) (observing that "the best achieving sources, and what they can achieve with respect to HAPs, might not be properly identified" when using an improper surrogate). The problems that arise from using PM as a surrogate for non-mercury metallic HAPs can be addressed by placing bagasse boilers in a separate subcategory of boilers.

Response: See the preamble for discussion of a subcategory related to bagasse boilers.

Commenter Name: Rachel Smolker
Commenter Affiliation: Biofuelwatch
Document Control Number: EPA-HQ-OAR-2002-0058-2805.1
Comment Excerpt Number: 9

Comment: Given the concentrations of metals such as arsenic, chromium, lead and mercury contamination levels that can exist in waste wood fuel streams, using PM as a surrogate for metal emissions in the boiler rules is inadequate. Biomass boilers burning contaminated wood will inevitably have greater metals emissions than those burning forest biomass, even if particulate levels are similar. A permissive set of rules that permits extensive use of secondary materials as fuel will virtually guarantee an increase in heavy metals emissions from biomass power, with emissions going undetected due to the reliance on particulate matter as a proxy for these toxins.

Response: See preamble for response on non-hazardous secondary materials. See the Identification of Non-Hazardous Materials That Are Solid Waste for further discussion on classification of secondary materials.

Commenter Name: Roy W. Wood
Commenter Affiliation: Eastman Kodak Company
Document Control Number: EPA-HQ-OAR-2002-0058-2917.1
Comment Excerpt Number: 10

Comment: PM does not correlate with HAP metals except to the degree that coals have uniform metals content. For sources that have very low metals in their fuel, they may have low metal HAP emissions even with moderately high PM levels. An option for complying with metal HAP emissions standards should be provided as an alternative to meeting the PM standard. This option was contained in the original boiler MACT rule and there is no reason not to include this option in the final rule.

Response: See the response to comment EPA-HQ-OAR-2002-0058-2941.1, excerpt 23.

Commenter Name: Sarah E. Amick
Commenter Affiliation: Rubber Manufacturers Association
Document Control Number: EPA-HQ-OAR-2002-0058-2941.1
Comment Excerpt Number: 19

Comment: EPA chose PM as a surrogate for non-mercury metallic HAP because "[m]ost, if not all, non-mercury metallic HAP emitted from combustion sources will appear on the flue gas fly-ash. Therefore, the same control techniques that would be used to control the fly-ash PM will control non-mercury metallic HAP." Id. In addition, EPA recognizes that using PM as a surrogate will eliminate costly performance testing to comply with multiple individual standards. Id. These reasons are sufficient to sustain use of PM as a surrogate for non-mercury metallic HAP. In National Lime, the D.C. Circuit held that as long as EPA demonstrates that there is a correlation between the HAP controlled (in that case, metals) and the surrogate (in that case, PM), "it need not quantify that correlation or assess its variability because PM control technology is such that each unit of PM emissions avoided 'carries' within it some quantum of HAP metals." Nat'l Lime Ass'n, 233 F.3d at 639.

Furthermore, EPA acknowledges that most sources generally emit PM that includes some amount and combination of metallic HAP. See Bluewater Network v. EPA, 370 F.3d 1, 18 (D.C. Cir. 2004) (upholding EPA's use of hydrocarbons as a surrogate for PM because, in part, HC contributes to PM pollution). As the D.C. Circuit has recognized, "[i]f HAP metals are invariably present in [source] PM, then even if the ratio of metals to PM is small and variable, or simply unknown, PM is a reasonable surrogate for the metals," assuming that PM control technology indiscriminately captures HAP metals, which is true here, and that there is no independent method of controlling the HAP which did not control for PM as well, which is also true here. Id.; see also Sierra Club v. EPA, 353 F.3d 976, 985 (D.C. Cir. 2004) (applying Nat'l Lime's "three-part analysis" of invariable presence, indiscriminate capture and sole method of control to uphold use of PM as a surrogate for HAP).

Response: EPA acknowledges the comment and agrees. It has finalized PM as a surrogate for non-Hg metals in the final rule.

Commenter Name: Sarah E. Amick
Commenter Affiliation: Rubber Manufacturers Association
Document Control Number: EPA-HQ-OAR-2002-0058-2941.1
Comment Excerpt Number: 20

Comment: EPA's decision to use PM (filterable) rather than PM2.5 is also reasonable because sources with wet scrubbers cannot measure PM2.5, making the surrogate more broadly applicable. In addition, the majority of the filterable PM emitted from units that are well-controlled for PM is PM2.5.[See 75 Fed.Reg. at 32,018.] This conclusion is supported by emission data obtained from units not equipped with wet scrubbers during EPA's information collection effort, and so EPA's use of PM (filterable) is reasonable.

Response: EPA acknowledges the comment and agrees. It has finalized PM as a surrogate for non-Hg metals in the final rule.

Commenter Name: David M. Kiser
Commenter Affiliation: International Paper Company
Document Control Number: EPA-HQ-OAR-2002-0058-2777.1
Comment Excerpt Number: 27

Comment: International Paper supports using PM as a surrogate for inorganic HAP as the primary form of the standard.

A total selected metals (TSM) limit is supported but only as an alternate form of the standard as it is helpful for predominately wood-firing and particularly resinated-wood firing common in wood products facilities, furniture, etc. PM is a much more workable form of the standard for pulp and paper facilities and should be retained regardless of TSM considerations.

Response: EPA acknowledges the comment. It has finalized PM as a surrogate for non-Hg metals in the final rule.

Commenter Name: Gary W. Kruger

Commenter Affiliation: Morton Salt
Document Control Number: EPA-HQ-OAR-2002-0058-2883.1
Comment Excerpt Number: 32

Comment: Use of PM as a Surrogate for Non-Mercury HAP Metals.
Morton Salt supports the Agency's use of PM as a surrogate for HAP metals. If non-mercury metallic HAPs are typically present in boiler and process heater PM, then even if the ratio of metals to PM is small and variable, or simply unknown, PM is a reasonable surrogate for the metals. Also, as EPA notes in the preamble to the proposed rule [75 FR 32018] most, if not all non-metallic HAP emitted from combustion sources will appear on the flue gas fly-ash. Therefore, the control technology installed to capture PM will capture HAP metals along with other particulates.

Response: EPA acknowledges the comment and agrees. It has finalized PM as a surrogate for non-Hg metals in the final rule.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 68

Comment: ACC supports the Agency's use of PM as a surrogate for non-mercury HAP metals. If non-mercury metallic HAPs are typically present in boiler and process heater PM, then even if the ratio of metals to PM is small and variable, or simply unknown, PM is a reasonable surrogate for the metals even if the ratio of metals to PM is small and variable, or simply unknown. Also, as EPA notes in the preamble to the proposed rule, "[m]ost, if not all non-metallic HAP emitted from combustion sources will appear on the flue gas fly-ash."[75 Fed. Reg. at 32018.] Therefore, the control technology installed to capture PM will capture HAP metals along with other particulates.

Response: EPA acknowledges the comment and agrees. It has finalized PM as a surrogate for non-Hg metals in the final rule.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 69

Comment: We support EPA's approach to use PM as a surrogate for non-mercury metallic HAP since metals are a component of particulate matter and testing for PM is simpler than testing for total metals.

Response: EPA acknowledges the comment and agrees. It has finalized PM as a surrogate for non-Hg metals in the final rule.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 71

Comment: ACC also supports EPA's suggestion to use filterable PM or TSM, as opposed to PM2.5 for addressing non-mercury metal HAPs, particularly where the test method (OTM 27) cannot be used in stacks with entrained water droplets.

Response: EPA acknowledges the comment and agrees. It has finalized PM as a surrogate for non-Hg metals in the final rule.

Choice of Regulated Pollutants: Alternative non-Hg metals

Commenter Name: Houston Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1876
Comment Excerpt Number: 136

Comment: EPA needs to include a total select metals unit as an alternative compliance approach for the proposed PM standard.

Response: See the response to comment EPA-HQ-OAR-2002-0058-2941.1, excerpt 23.

Commenter Name: Houston Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1876
Comment Excerpt Number: 148

Comment: EPA should include total select metals limit as an alternative compliance approached for the proposed particulate matter standard.

Response: See the response to comment EPA-HQ-OAR-2002-0058-2941.1, excerpt 23.

Commenter Name: David Bonistall
Commenter Affiliation: NewPage Corp
Document Control Number: EPA-HQ-OAR-2002-0058-2920.1
Comment Excerpt Number: 4

Comment: To enhance flexibility in the proposed rule, we believe that EPA should also include a total selected metals (TSM) emission limitation as an alternative to the proposed particulate matter emission limit. NewPage believes inclusion of a TSM emission limitation as an alternative to the proposed particulate matter emission limit is appropriate since the emissions of these non-mercury metals are the hazardous air pollutants the standard is intending to regulate.

The inclusion of a TSM option will provide greater flexibility for sources while still protecting the environment from the emissions of non-mercury HAP metals. This would offer the opportunity for sources to achieve low metal HAP emissions similar to those achieved with PM, but potentially at a lower cost. As the proposed Boiler MACT rule will be extremely costly for industry, the use of the TSM alternative will help to ensure some cost savings by avoiding the installation and use of PM CEMS.

For purposes of the Boiler MACT rule, TSM would be defined as the sum of the 10 non-mercury HAP metals identified in the Clean Air Act HAP list (e.g. antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, nickel and selenium). It would not be practical or necessary for EPA to set emission limits for each of these individual metals due to the fact that so many of them are present below detectable levels. The use of a TSM alternative is therefore appropriate, and TSM emissions can be calculated using available metals emission data for each fuel type and sub-category. The use of a total makes more sense, but EPA will need to develop a scientifically defensible method for addressing the handling of non-detect test results. This guidance on how to treat non-detects will need to be include in the rule instructions since there is no guidance in Method 29. This methodology will need to provide assurance to facilities that test results which are below measurable levels (e.g. non-detects) will not put sources in a situation of being non-compliant with the standard. In the comments submitted by NCASI, there is a lengthy discussion on analytical detection limit issues.

Response: See the response to comment EPA-HQ-OAR-2002-0058-2941.1, excerpt 23.

Commenter Name: Sean M. O'Keefe
Commenter Affiliation: Alexander and Baldwin, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-3196
Comment Excerpt Number: 8

Comment: As was done in the vacated Boiler MACT standard, EPA has proposed an emissions limit for particulate matter (PM) as a surrogate for the control of metal HAPs. Unlike the vacated standard, however, this proposal does not allow for the option to comply with limits on the underlying metals themselves as an alternative to the PM limit.

Under the vacated standard, many facilities (including HC&S) that were unable to comply with the PM limit with their existing air pollution controls were able to demonstrate compliance with limits on emissions of metals and thereby avoid the need to install costly new PM emissions controls. Because metals make up only a fraction of total particulate matter emissions, control of PM to the levels proposed by EPA (for HC&S, a reduction of 80 to 90 percent from current emissions) may be unnecessary in order to achieve the desired level of control of HAP metals emissions. Since a major portion of the overall cost of compliance with the proposed rule is likely to result from the need to install new PM emissions controls, inclusion of an option to instead comply with an emissions limit on metals could again significantly reduce overall compliance costs while still meeting the objective of the rule to control emissions of hazardous air pollutants. A&B strongly encourages EPA to again include this option in the final rule as a means of increasing flexibility and reducing the overall economic impact of the rule.

Response: See the response to comment EPA-HQ-OAR-2002-0058-2941.1, excerpt 23.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 88

Comment: AF&PA supports the Agency's use of PM as a surrogate for HAP metals. If non-mercury metallic HAPs are typically present in boiler and process heater PM, then even if the ratio of metals to PM is small and variable, or simply unknown, PM is a reasonable surrogate for the metals. Also, as EPA notes in the preamble to the proposed rule [75 FR 32018] "[m]ost, if not all non-mercury metallic HAP emitted from combustion sources will appear on the flue gas fly-ash". Therefore, the control technology installed to capture PM will capture HAP metals along with other particulates.

In the preamble to the proposed rule, EPA states that the "selection of numerical emission limits as the format for this proposed rule provides flexibility for the regulated community by allowing a source to choose any control technology or technique to meet the emission limits" (page 32017). We understand EPA's approach to use particulate matter as a surrogate for non-mercury metallic HAP since metals are a component of particulate matter and testing for PM is simpler than testing for total metals. However, to enhance flexibility in the proposed rule, AF&PA believes that EPA should include a total selected metals (TSM) emission limitation as an alternative to the proposed particulate matter emission limit (i.e., the sum of the 10 non-mercury HAP metals identified in the Clean Air Act HAP list: antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, nickel, and selenium). AF&PA believes inclusion of a TSM emission limitation as an alternative to the proposed particulate matter emission limit is appropriate since the emissions of these non-mercury metals are the hazardous air pollutants the standard is intending to regulate.

We believe that inclusion of such a TSM option will provide greater flexibility for sources while still protecting the environment from the emissions of non-mercury HAP metals. This would offer the opportunity for sources to achieve low metal HAP emissions similar to those achieved with PM, but potentially at a lower cost. As the proposed Boiler MACT rule will be extremely

costly for industry, the use of the TSM alternative will help to ensure some cost savings by avoiding the installation and use of PM CEMS.
For purposes of the Boiler MACT rule, TSM would be defined as the sum of the 10 non-mercury HAP metals. It would not be practical or necessary for EPA to set emission limits for each of these individual metals due to the fact that so many of them are present below detectable levels. The use of a TSM alternative is therefore appropriate, and TSM emissions can be calculated using available metals emission data for each fuel type and sub-category.

Response: See the response to comment EPA-HQ-OAR-2002-0058-2941.1, excerpt 23.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 90

Comment: Since EPA used PM as a surrogate for non-mercury metallic HAPs in the proposed rule it also makes sense for EPA to use the PM floor units as the total selected metals (TSM) top performers. It is appropriate for EPA to consider TSM emission information only from top PM performers since the metals data are associated with particulate emissions and EPA has determined that PM is an appropriate surrogate for non-mercury metals. Using the TSM emission data from the top PM performers will also assure that the TSM limits reflect the maximum particulate removal since the floor data are limited to only those units that are the best performers for removing particulate.
Although an alternate approach to creating a TSM limit would be for EPA to use only the available TSM-10 data to create emission limits, AF&PA does not support this approach, as the amount of data to determine the TSM floors for each subcategory would be much more limited than our proposed approach. This is due to the fact that data for all 10 non-mercury HAP metals were only collected during the ICR Phase 2 testing. Then taking the top 12% of that small dataset provides very few units to determine the floor. As stated in other sections of these comments, AF&PA is already concerned about limited data sets being used to determine these floors and this approach would worsen that situation. However, since many of the top PM performers were also in the Phase 2 testing and tested for TSM-10, using data from these units provides a more robust dataset for determining a MACT floor for TSM-10.
The submitted table shows the TSM limits calculated using the PM top performers per the MACT floor memo (we note again our concerns about data quality and urge EPA to quality assure the TSM-10 data in the database prior to finalizing any analysis, but have presented the results of our analysis of the available data in an effort to provide detailed comments).

Response: See the response to comment EPA-HQ-OAR-2002-0058-2941.1, excerpt 23.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)

Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 91

Comment: We believe that the framework already exists in the rule to ensure that sufficient monitoring is performed for a TSM alternative standard. The proposed rule [75 FR 32056, §63.7530(b)] contains procedures for determining initial compliance with mercury and hydrogen chloride through stack testing and fuel analysis. This approach could be easily adapted for a TSM standard as well. The proposed rule [75 FR 32056, §63.7540(a)(2)] also contains procedures for determining continuous compliance with mercury and hydrogen chloride and could be adapted to TSM. If a source selects the TSM alternative, there would not be the need to continuous monitor PM emissions. While the TSM alternative may entail increased costs for stack testing and fuel analysis, the costs associated with the initial installation and on-going maintenance and manpower support for a PM continuous monitor will not be incurred.

Response: See the response to comment EPA-HQ-OAR-2002-0058-2941.1, excerpt 23.

Commenter Name: Chris Greissing
Commenter Affiliation: Industrial Minerals Association
Document Control Number: EPA-HQ-OAR-2002-0058-2740.2
Comment Excerpt Number: 16

Comment: EPA should provide for an alternative emission limit for the non-mercury HAP metals as was done in the prior Subpart DDDDD rule, measured by Total Selected Metals, or TSM. Sources should then be allowed to demonstrate compliance via fuel analysis or by conducting stack testing using EPA Reference Method 29 (this test is already required for Hg compliance demonstration and can provide results for the remaining metals). If EPA is sincere in its sensitivity to costs, this is a very cost-effective alternative as compared to installation and operation of PM CEMS. A TSM alternate standard is a cost-effective alternative that also provides a better correlation between the surrogate TSM measure and total HAP metals.

Response: See the response to comment EPA-HQ-OAR-2002-0058-2941.1, excerpt 23.

Commenter Name: David A. Buff
Commenter Affiliation: Golder Associates Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2801.1
Comment Excerpt Number: 31

Comment: The cost of performance testing for individual metallic HAP will be miniscule compared to the need to retrofit expensive control devices due to a restrictive PM standard. Moreover, all metallic HAP emissions can be tested in a single Method 29 sampling train, requiring no more manpower than a Method 5 PM test.

FSI urges EPA to set individual metallic HAP emission limits, similar to the previous, now vacated Industrial Boiler MACT standards. The previous standards set a metallic HAP limit as the total of eight metals.

Response: See the response to comment EPA-HQ-OAR-2002-0058-2941.1, excerpt 23.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-2702.1
Comment Excerpt Number: 196

Comment: Total Selected Metals as an Alternative Compliance Measure.
PM is clearly an appropriate surrogate for non-mercury metallic HAP. However, EPA should provide an alternative compliance measure for non-mercury metallic HAPs where a source burns fuel containing very little metals but sufficient PM emissions to require control under the PM provisions of the Proposed Rule. Otherwise, for those sources that burn fuel containing very little metals, EPA is simply setting a PM emission limit. In the 2004 Boiler MACT, EPA recognized that in such cases PM would not be an appropriate surrogate for metallic HAPs. See EPA-HQ-OAR-2002-0058-0013, National Emission Standards for Hazardous Air Pollutants for Industrial/Commercial/Institutional Boilers and Process Heaters; Proposed Rule, 68 FR 1,660, 1,671 (Jan. 13, 2003). EPA proposed an alternative metals emission limit set for the sum of emissions of eight selected metals: arsenic, beryllium, cadmium, chromium, lead, manganese, nickel and selenium, also known as the total selected metals or "TSM," representing "the most common and largest emitted metallic HAP from boilers and process heaters." Id. EPA determined that this alternative TSM surrogate was appropriate because sufficient information was not available for each metallic HAP for every fuel type, but a total metals number could be calculated for every fuel type. See EPA-HQ-OAR-2002-0058, National Emission Standards for Hazardous Air Pollutants for Industrial/Commercial/Institutional Boilers and Process Heaters; Final Rule, 69 FR 55,218, 55,231 (Sept. 13, 2004).

Some sources burn fuels that contain very low concentrations of metals but that have sufficient PM emissions to require control under the proposed PM MACT floor. Under those circumstances, PM would not serve as an appropriate surrogate. For these sources, it is not necessary to install controls to control the metallic HAP; rather, the benefit of such controls would be to control PM, which is not a HAP regulated under section 112. MACT standards, however, may only address HAPs. See Nat'l Lime Ass'n, 233 F.3d at 638. Section 112(d)(2) provides an express list of factors that EPA may consider in setting MACT standards – including "the cost of achieving such emission reduction, and any non-air quality health and environmental impacts and energy requirements." This list does not allow consideration of non-HAP air quality benefits, such as the co-benefits of reducing sulfur dioxide and other non-HAP emissions. Moreover, the CAA provides other mechanisms for reducing such emissions.

Allowing these sources to comply with an alternative emission limit for total selected metals (TSM) would meet EPA's objective of controlling non-mercury metallic HAP emissions without triggering unnecessary control requirements that are otherwise beyond the scope of section 112.

This is consistent with DC Circuit decisions affirming the use of surrogates in other MACTs. Where a surrogate is appropriate and defensible for some but not all sources or all pollutants in a category of pollutants, EPA has not discarded the surrogate, but instead devised parameters for its reasonable application where appropriate. For example, in this proposed rulemaking, EPA has elected to use CO for organics, but carved out one subset of organics – dioxins – to be separately controlled. Inherent in the use of a surrogate is that it will have logical limits to its appropriateness.

Response: See the response to comment EPA-HQ-OAR-2002-0058-2941.1, excerpt 23.

Commenter Name: Traylor Champion
Commenter Affiliation: Georgia-Pacific LLC
Document Control Number: EPA-HQ-OAR-2002-0058-2745.1
Comment Excerpt Number: 4

Comment: Congress established non-mercury metals of concern
In the 1990 Clean Air Amendments, Congress listed 10 non-mercury metals as hazardous air pollutants: antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, nickel, and selenium. EPA was instructed to set MACT standards to reduce emissions of these 10 metals. In the proposed rule, EPA appropriately selected particulate matter as a surrogate for these metals since most of them are attached to particulate matter that is captured in appropriate control devices. GP supports this surrogate selection. However, EPA should consider an alternative compliance demonstration for sources that want to control the total of these 10 metals. This would directly meet the intent of Congress to control the metals of concern.

Response: See the response to comment EPA-HQ-OAR-2002-0058-2941.1, excerpt 23.

Commenter Name: Traylor Champion
Commenter Affiliation: Georgia-Pacific LLC
Document Control Number: EPA-HQ-OAR-2002-0058-2745.1
Comment Excerpt Number: 5

Comment: EPA promulgated a TSM limit in the vacated Boiler MACT rule
In the vacated Boiler MACT rule, EPA promulgated a TSM alternative for PM. (In the vacated rule EPA chose to regulate only eight of the metals, excluding cobalt and antimony). It only makes sense that EPA should add this option for this rule for the same reasons that it was included in the vacated rule.

Response: See the response to comment EPA-HQ-OAR-2002-0058-2941.1, excerpt 23.

Commenter Name: Traylor Champion
Commenter Affiliation: Georgia-Pacific LLC
Document Control Number: EPA-HQ-OAR-2002-0058-2745.1
Comment Excerpt Number: 6

Comment: EPA collected extensive emissions data for these metals
As part of the Information Collection Request (ICR) in support of this proposed rule, EPA required extensive emission testing by a large number of facilities. One of the tests required of the selected facilities was to analyze boiler emissions for the ten total select metals. The mere fact that EPA required analysis of TSM suggests that the Agency intended to use these data in the proposed rule, and justified the significant expense required on the part of the sources to produce it. However, EPA did not propose any limits nor did it explain in the preamble to the proposed rule why a TSM alternative was not included in the proposed rule.

Response: See the response to comment EPA-HQ-OAR-2002-0058-2941.1, excerpt 23.

Commenter Name: Traylor Champion
Commenter Affiliation: Georgia-Pacific LLC
Document Control Number: EPA-HQ-OAR-2002-0058-2745.1
Comment Excerpt Number: 7

Comment: This will significantly reduce compliance costs.
A TSM option will provide greater flexibility for sources while still protecting the environment from the emissions of non-mercury HAP metals. This would offer the opportunity for sources, including several GP facilities, to achieve low metal HAP emissions similar to those achieved with PM, but potentially at a lower cost.
Across the forest products industry, these rules could cost $6 billion over the next four years. This would result in severe hardship and tens of thousands of job losses in the forest products sector alone. The cost of these rules translates to tens of millions in additional capital expenditures which may not be sustainable given the economic downturn and fierce international competition. As a significant player in the forest products industry, GP could have to spend hundreds of million of dollars at its 82 solid fuel and oil-fired boilers. Were EPA to adopt the additional flexibility of a total select metals compliance option, GP could save tens of millions of dollars while still protecting the environment as envisioned by the Clean Air Act

Response: See the response to comment EPA-HQ-OAR-2002-0058-2941.1, excerpt 23.

Commenter Name: Sarah E. Amick

Commenter Affiliation: Rubber Manufacturers Association
Document Control Number: EPA-HQ-OAR-2002-0058-2941.1
Comment Excerpt Number: 23

Comment: PM is clearly an appropriate surrogate for non-mercury metallic HAP. However, EPA should provide an alternative compliance measure for non-mercury metallic HAPs where a source burns fuel containing very little metals but sufficient PM emissions to require control under the PM provisions of the proposed rule. Otherwise, for those sources that burn fuel containing very little metals, EPA is simply setting a PM emission limit. In the 2004 Boiler MACT, EPA recognized that in such cases PM would not be an appropriate surrogate for metallic HAPs. See EPA-HQOAR-2002-0058-0013, National Emission Standards for Hazardous Air Pollutants for Industrial/Commercial/Institutional Boilers and Process Heaters; Proposed Rule, 68 Fed.Reg. 1,660, 1,671 (Jan. 13, 2003). EPA proposed an alternative metals emission limit set for the sum of emissions of eight selected metals: arsenic, beryllium, cadmium, chromium, lead, manganese, nickel and selenium, also known as the total selected metals or "TSM," representing "the most common and largest emitted metallic HAP from boilers and process heaters." Id. EPA determined that this alternative TSM surrogate was appropriate because sufficient information was not available for each metallic HAP for every fuel type, but a total metals number could be calculated for every fuel type. See EPA-HQ-OAR-2002-0058, National Emission Standards for Hazardous Air Pollutants for Industrial/Commercial/Institutional Boilers and Process Heaters; Final Rule, 69 Fed.Reg. 55,218, 55,231 (Sept. 13, 2004).

Some sources burn fuels that contain very low concentrations of metals but that have sufficient PM emissions to require control under the proposed PM MACT floor. Under those circumstances, PM would not serve as an appropriate surrogate. For these sources, it is not necessary to install controls to control the metallic HAP; rather, the benefit of such controls would be to control PM, which is not a HAP regulated under section 112. MACT standards however, may only address HAPs. See Nat'l Lime Ass'n, 233 F.3d at 638. Section 112(d)(2) provides an express list of factors that EPA may consider in setting MACT standards – including "the cost of achieving such emission reduction, and any non-air quality health and environmental impacts and energy requirements." This list does not allow consideration of non-HAP air quality benefits, such as the co-benefits of reducing sulfur dioxide and other non-HAP emissions. Moreover, the CAA provides other mechanisms for reducing such emissions.

Allowing these sources to comply with an alternative emission limit for total selected metals (TSM) would meet EPA's objective of controlling non-mercury metallic HAP emissions without triggering unnecessary control requirements that are otherwise beyond the scope of section 112.

This is consistent with DC Circuit decisions affirming the use of surrogates in other MACTs. Where a surrogate is appropriate and defensible for some but not all sources or all pollutants in a category of pollutants, EPA has not discarded the surrogate, but instead devised parameters for its reasonable application where appropriate. For example, in this proposed rulemaking, EPA has elected to use CO for organics, but carved out one subset of organics – dioxins – to be separately controlled. Inherent in the use of a surrogate is that it will have logical limits to its appropriateness.

Response: Although the vacated rule contained a TSM alternative standard, the rule also included a health based alternative to exclude manganese while complying with the TSM alternative limit. Unlike the vacated rule we are not finalizing health based alternatives and EPA determined a TSM alternative would not provide much additional flexibility to regulated sources.

The non-Hg metal HAP are very likely to be present in the particulate phase and will be captured along with the filterable PM in the primary PM control device. The partitioning of the metal HAPs is very complicated and can depend upon the fuel type, the form of the metals in the fuel, other constituents in the fuel and the time-temperature profile of the post-combustion environment. EPA's Office of Research & Development has conducted studies that showed good control of the non-Hg metal HAP followed good control of bulk PM (filterable) across the primary PM control device.

Commenter Name: Gary W. Kruger
Commenter Affiliation: Morton Salt
Document Control Number: EPA-HQ-OAR-2002-0058-2883.1
Comment Excerpt Number: 33

Comment: In the preamble to the proposed rule, EPA states that the selection of numerical emission limits as the format for this proposed rule provides flexibility for the regulated community by allowing a source to choose any control technology or technique to meet the emission limits. We understand EPA’s approach to use particulate matter as a surrogate for non-mercury metallic HAP since metals are a component of particulate matter, and testing for PM is simpler than

testing for total metals. However, to enhance flexibility in the proposed rule, we believe that EPA should include a total selected metals (TSM) emission limitation as an alternative to the proposed particulate matter emission limit (i.e., the sum of the 10 non-mercury HAP metals identified in the Clean Air Act HAP list: antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, nickel, and selenium). We believe inclusion of a TSM emission limitation as an alternative to the proposed particulate matter emission limit is appropriate since the emissions of these non-mercury metals are the hazardous air pollutants the standard is intending to regulate.
We believe that inclusion of such a TSM option will provide greater flexibility for sources while still protecting the environment from the emissions of non-mercury HAP metals. This would offer the opportunity for sources to achieve low metal HAP emissions similar to those achieved with PM, but potentially at a lower cost. As the proposed Boiler MACT rule will be extremely costly for industry, the use of the TSM alternative will help to ensure the installation of additional PM control technology only occurs on sources with high non-mercury metallic HAP emissions.

For purposes of the Boiler MACT rule, TSM would be defined as the sum of the 10 non-mercury HAP metals. It would not be practical or necessary for EPA to set emission limits for each of these individual metals due to the fact that so many of them are present below detectable levels. The use of a TSM alternative is therefore appropriate, and TSM emissions can be calculated using available metals emission data for each fuel type and sub-category. The use of a total makes more sense, but EPA should include in the rule instructions on how to treat non-detects since there is no guidance in Method 29.

Since EPA used PM as a surrogate for non-mercury metallic HAPs in the proposed rule, it also makes sense for EPA to use the PM floor units as the TSM top performers. It is appropriate for EPA to consider TSM emission information only from top PM performers since the metals data are associated with particulate emissions, and EPA has determined that PM is an appropriate surrogate for non-mercury metals. Using the TSM emission data from the top PM performers will also assure that the TSM limits reflect the maximum particulate removal since the floor data are limited to only those units that are the best performers for removing particulate. We considered and rejected an alternative methodology for determining a TSM limit. If EPA were to use only the available TSM data to create emission limits, data would be much more limited to determine the subcategory TSM floors. This is due to the fact that data for all 10 non-mercury HAP metals were only collected during the ICR Phase 2 testing. Then taking the top 12% of that small dataset provides very few units to determine the floor. As stated in other sections of these comments, we are already concerned about limited data sets being used to determine these floors and this approach would worsen that situation. However, since many of the top PM performers were also in the Phase 2 testing and tested for TSM-10, using data from these units provides a more robust dataset for determining a MACT floor for TSM-10. See submittal for a table showing the TSM limits calculated using the PM top performers per the MACT floor memo.

We believe that the framework already exists in the rule to ensure that sufficient monitoring is performed for a TSM alternative standard. The proposed rule [75 FR 32056, §63.7530(b)] contains procedures for determining initial compliance with mercury and hydrogen chloride through stack testing and fuel analysis. This approach could be easily adapted for a TSM standard as well. The proposed rule [75 FR 32056, §63.7540(a)(2)] also contains procedures for determining continuous compliance with mercury and hydrogen chloride and could be adapted to TSM. If a source selects the TSM alternative, there would not be the need to continuous monitor PM emissions. While the TSM alternative maybe require increased costs for stack testing and fuel analysis, the costs associated with the initial installation and on-going maintenance and manpower support for a PM continuous monitor will not be incurred.

Response: See the response to comment EPA-HQ-OAR-2002-0058-2941.1, excerpt 23.

Commenter Name: Gary W. Kruger
Commenter Affiliation: Morton Salt
Document Control Number: EPA-HQ-OAR-2002-0058-2883.1
Comment Excerpt Number: 34

Comment: We support the use of filterable PM or TSM and not PM2.5 for addressing non-mercury metal HAPs. As the purpose of the MACT standards is to limit emissions of HAP, establishing a PM2.5 emission limit is not appropriate.

Response: EPA acknowledges the comment and agrees. It has finalized PM as a surrogate for non-Hg metals in the final rule.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 70

Comment: To enhance flexibility in the proposed rule, ACC recommends that EPA include a total selected metals (TSM) [The sum of the 10 non-mercury HAP metals identified in the Clean Air Act HAP list: antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, nickel, and selenium.] emission limitation as an alternative to the proposed PM emission limit. ACC believes inclusion of a TSM emission limitation as an alternative to the proposed PM emission limit is appropriate since the emissions of these non-mercury metals are the hazardous air pollutants the standard targets for regulation and reduction.

TSM would also offer the opportunity for sources to achieve low metal HAP emissions similar to those achieved with PM, but potentially at a lower cost, particularly where it may help avoid the installation and operation of PM continuous emissions monitoring.

A TSM approach does not require EPA to set emission limits for each of the individual metals, as so many of them are present below detectable levels. TSM emissions can be calculated using available metals emission data for each fuel type and sub-category. EPA should indicate that if individual metals are non-detect for all 3 test runs or fuel samples (using Method 29 or fuel analysis), emissions of those metals should be counted as zero.

Since EPA used PM as a surrogate for non-mercury metallic HAPs in the proposed rule it also makes sense for EPA to use the PM floor units as the TSM for top performers. It is appropriate for EPA to consider TSM emission information only from top PM best performers since the metals data are clearly associated with particulate emissions, and EPA has determined that PM is an appropriate surrogate for non-mercury metals. Using the TSM emission data from the top PM best performers to establish the floor will also assure that the TSM limits reflect the maximum degree of reduction being achieved by the best performing 12% of existing sources.

The table below shows the TSM limits calculated using the PM top performers per the MACT floor memo. [ACC notes again our concerns about data quality. We urge EPA to quality assure the TSM-10 data in the database prior to finalizing any analysis, but have presented the results of our analysis of the available data in an effort to provide detailed comments.] [see submittal for Table 7, TSM limits calculated using the PM top performers per the MACT floor memo.]

ACC believes that a framework already exists in the proposed rule to ensure that sufficient monitoring is performed for a TSM alternative standard. Proposed section 63.7530(b) of the rule contains procedures for determining initial compliance with mercury and hydrogen chloride through stack testing and fuel analysis. This approach could be easily adapted for a TSM standard as well. The proposal also contains procedures for determining continuous compliance with mercury and hydrogen chloride and could be adapted to TSM.64 If a source selects the TSM alternative, there would not be the need to continuously monitor PM emissions. While the TSM alternative may entail increased costs for stack testing and fuel analysis, the significant costs associated with the initial installation and on-going maintenance and manpower support for a PM continuous monitor would not be incurred.

Response: See the response to comment EPA-HQ-OAR-2002-0058-2941.1, excerpt 23.

Choice of Regulated Pollutants: HCl

Commenter Name: Cathy S. Woollums
Commenter Affiliation: MidAmerican Energy Holdings Company
Document Control Number: EPA-HQ-OAR-2002-0058-2786.1
Comment Excerpt Number: 4

Comment: With HCl, the emissions test information available indicate that the primary inorganic HAPs emitted from boilers and process heaters are acid gases, with HCl present in the largest amounts. Further, control technologies that would reduce HCl would also control other inorganic compounds that are acid gases. Thus, the best controls for HCl would also be the best controls for other inorganic HAPs that are acid gases. Therefore, HCl is a good surrogate for acid gas inorganic HAPs because controlling HCl will result in a corresponding control of other acid gas inorganic HAP emissions.

Response: EPA acknowledges the comment and agrees. It has finalized HCl as a surrogate for non-metallic inorganic HAP in the final rule.

Commenter Name: N/A
Commenter Affiliation: Sierra Club, Clean Air Task Force, Earthjustice, and Natural Resources Defense Council
Document Control Number: EPA-HQ-OAR-2002-0058-3187.1
Comment Excerpt Number: 12

Comment: B. EPA's Choice of HCl as a Surrogate For non-metal inorganic HAPs (Acid Gases) is Unlawful, Arbitrary, and Capricious.

EPA's choice of HCl as the surrogate for all non-metallic inorganic HAPs emitted by ICIBPH fails all three prongs of the Sierra Club test for the choice of a reasonable surrogate. EPA offers very little support for this choice in the preamble to the proposed rule – certainly not sufficient support to satisfy the Sierra Club three part test for surrogacy. While the emissions test data show that the primary non-metallic inorganic HAP emitted from boilers and process heaters are acid gases, with HCl present in the largest amounts, the agency does not say or show that all the other acid gases are "invariably" present when HCl is present – or that their emissions concentrations fluctuate directly with HCl emissions levels. Indeed, this is not a showing EPA can make – for example, HCN peaks intermittently when coal is burned, while HCl does not. [See submittal for Reference 9.] Moreover these pollutants are "fuel dependent" – each different combination of fuels burned will produce different proportions of these pollutants, and different peaks. An examination of the emissions profiles of three units in EPA's sampling show that the relationship between HCl and other inorganic non-metal HAPs varies by fuel mix. The emissions database and survey database in the docket support only the assertion that HCl is present in much higher concentrations than the other acid gases, but not that the other acid gases are 'invariably present' with HCl. The emissions database contains approximately 44,000 data points for major and area source boilers. A quick scan of the acid gas values shows that HCl emissions were reported in pounds per Million British Thermal Units (lb/mmBtu) and ranged from roughly 0.00001 to 0.8. The database contains information on type of fuel burned, type of control technology, and type of sample collected. Table III-1 gives examples of the information for three boilers. [See submittal for Table III-1 showing sample emission rates for acid gases from boilers burning various fuel combinations.]

Although EPA asserts that control technologies that reduce HCl also control other inorganics like chlorine and other acid gases, the agency does not say that these controls "indiscriminately capture" other acid gases, or that they are the "only" controls available for the other gases, only that the "the best controls for HCl would also be the best controls for other inorganic HAP that are acid gases." While applying the best controls on HCl may be a laudable goal, this explanation is not sufficient to support the choice of HCl as a surrogate for HF, Cl2, and hydrogen cyanide. EPA must show that these other acid gases are invariably present when HCl is present in the exhaust gases from each of the subcategories it has selected, that controls on HCl indiscriminately also capture these other acid gases, and that such controls are the only way facilities now actually achieve lowered acid gas emissions levels. This EPA fails to do with this proposal; indeed by allowing sources to "elect[] to demonstrate compliance with the HCl or mercury limit by using fuel which has a statistically lower pollutant content than the emissions limit," 75 Fed. Reg. 32,033, EPA has openly acknowledged that fuel-switching is an available method of reducing both pollutants.

Response: The acid-gas HAP (HCl, HF, HCN and Cl2) are expected to be removed using technologies that take advantage of their solubility or their acidity (or both). This will likely be done using technologies that are often used for control of SO2 or SO3 (also acidic gases). Because it is highly likely that facilities will choose to control these acid gases by applying the same technology and the means of removal for each are similar, it is logical to select one (HCl) as a surrogate to represent the control of the others.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 94

Comment: AF&PA supports the use of HCl as a surrogate for inorganic HAP. The justification for using HCl as a surrogate for inorganic HAP is similar to the justification for use of PM as a surrogate for non-mercury HAP metals, in that control technologies that would reduce HCl would also control other inorganic compounds that are acid gases. Thus, the best controls for HCl would also be the best controls for other inorganic HAP that are acid gases.

Response: EPA acknowledges the comment and agrees. It has finalized HCl as a surrogate for non-metallic inorganic HAP in the final rule.

Commenter Name: David A. Buff
Commenter Affiliation: Golder Associates Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2801.1
Comment Excerpt Number: 33

Comment: The FSI agrees that hydrogen chloride (HCl) is an appropriate surrogate for inorganic HAP. The primary inorganic HAPs are HCl and hydrogen fluoride, but HCl is much more prevalent in biomass.

Response: EPA acknowledges the comment and agrees. It has finalized HCl as a surrogate for non-metallic inorganic HAP in the final rule.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-2702.1
Comment Excerpt Number: 193

Comment: HCl as a surrogate for non-metallic inorganic HAP.
EPA chose HCl as a surrogate for non-metallic inorganic HAP because "the emissions test information available to EPA indicate that the primary non-metallic inorganic HAP emitted from boilers and process heaters are acid gases, with HCl present in the largest amounts." 75 FR 32018. EPA found that other inorganic compounds emitted are found in much smaller quantities than HCl. Id. In addition, "[c]ontrol technologies that reduce HCl also control other inorganic compounds such as chlorine and other acid gases." EPA's reasoning is thus consistent with Nat'l Lime and Sierra Club because it has demonstrated a "[s]trong direct correlation" between HCl and acid gases, in that the data demonstrates that HCl is present in acid gas emissions, usually in the largest amounts. Sierra Club, 353 F.3d at 985. In addition, EPA has shown that the best

control technologies for HCl are also the best controls for other inorganic HAP that are acid gases. 75 FR at 32,018; see Nat'l Lime, 233 F.3d at 639. This is a sufficient basis for EPA to use HCl as a surrogate for non-metallic inorganic HAP. See Bluewater Network, 370 F.2d at 18 (EPA use of surrogate was reasonable surrogate provides a "good proxy" for regulating other emissions).

Response: EPA acknowledges the comment and agrees. It has finalized HCl as a surrogate for non-metallic inorganic HAP in the final rule.

Commenter Name: Sarah E. Amick
Commenter Affiliation: Rubber Manufacturers Association
Document Control Number: EPA-HQ-OAR-2002-0058-2941.1
Comment Excerpt Number: 21

Comment: EPA chose HCl as a surrogate for non-metallic inorganic HAP because "the emissions test information available to EPA indicates that the primary non-metallic inorganic HAP emitted from boilers and process heaters are acid gases, with HCl present in the largest amounts." 75 Fed.Reg. at 32,018. EPA found that other inorganic compounds emitted are found in much smaller quantities than HCl. Id. In addition, "[c]ontrol technologies that reduce HCl also control other inorganic compounds such as chlorine and other acid gases." EPA's reasoning is thus consistent with Nat'l Lime and Sierra Club because it has demonstrated a "[s]trong direct correlation" between HCl and acid gases, in that the data demonstrates that HCl is present in acid gas emissions, usually in the largest amounts. Sierra Club, 353 F.3d at 985. In addition, EPA has shown that the best control technologies for HCl are also the best controls for other inorganic HAP that are acid gases. 75 Fed.Reg. at 32,018; see Nat'l Lime, 233 F.3d at 639. This is a sufficient basis for EPA to use HCl as a surrogate for non-metallic inorganic HAP. See Bluewater Network, 370 F.2d at 18 (EPA use of surrogate was reasonable surrogate provides a "good proxy" for regulating other emissions).

Response: EPA acknowledges the comment and agrees. It has finalized HCl as a surrogate for non-metallic inorganic HAP in the final rule.

Commenter Name: Sheila C. Holman
Commenter Affiliation: North Carolina Department of Environment and Natural Resources
Document Control Number: EPA-HQ-OAR-2002-0058-2798.1
Comment Excerpt Number: 32

Comment: Hydrogen chloride (HCI) appears to be an appropriate surrogate for the other acid gases under consideration, hydrogen fluoride (HF), hydrogen cyanide (HCN), and chlorine (CI2). This assessment is based on the following:

All of these gases are water soluble and can be effectively controlled by the same means (i.e. wet scrubbers or spray dryer absorbers). HCI control systems commonly operate with control efficiencies of 95% or more. While the control efficiencies of HF, HCN, and CI2 may be somewhat less than for HCI, because of their much lower uncontrolled emissions rates, these gases can still be controlled to low levels.

Compared to HCI, the emissions for the other acid gases are considerably lower.
Based on AP-42 emissions factors for coal combustion, uncontrolled HF and HCN are emitted at 12% and 0.2% the rate of HCI, respectively. While AP-42 does not list Cb emission factors for coal combustion, emissions of Cf2 from typical combustion processes are expected to be extremely low given its reactivity.

The higher toxicities of HF, HCN, and CI2 relative to HCI are more than offset by the relatively lower emissions rates of these gases. If acid gas emissions are controlled to levels that effectively limit adverse health effects from Hel exposures, the health effects from the other acid gases should also be effectively limited.

Setting conventional MACT standards for HCI as well as PM, would result in significant reductions in emissions of other pollutants, most notably for sulfur dioxide, non-condensable PM, and other non·HAP acid gases. It would likely also result in additional reductions in emissions of mercury and other HAP metals.

Response: EPA acknowledges the comment and agrees. It has finalized HCl as a surrogate for non-metallic inorganic HAP in the final rule.

Commenter Name: Gary W. Kruger
Commenter Affiliation: Morton Salt
Document Control Number: EPA-HQ-OAR-2002-0058-2883.1
Comment Excerpt Number: 35

Comment: We support the use of HCl as a surrogate for inorganic HAP. The justification for using HCl as a surrogate for inorganic HAP is similar to the justification for use of PM as a surrogate for non-mercury HAP metals, in that control technologies that would reduce HCl would also control other inorganic compounds that are acid gases. Thus, the best controls for HCl would also be the best controls for other inorganic HAP that are acid gases.

Response: EPA acknowledges the comment and agrees. It has finalized HCl as a surrogate for non-metallic inorganic HAP in the final rule.

Commenter Name: Gary W. Kruger
Commenter Affiliation: Morton Salt
Document Control Number: EPA-HQ-OAR-2002-0058-2883.1

Comment Excerpt Number: 36

Comment: The proposed dioxin/furan emission standards are so low and the detection limits of dioxin/furan isomers are so variable that many boilers are likely to exceed the proposed emission limits for dioxins/furans even though the tests show that all the isomers are present below the detection limits for the 17 isomers. Given that the detection limit is used to differentiate between a blank and presence of an analyte, the above outcome is unreasonable and completely impractical. Consequently, we recommend that EPA should replace the proposed numerical standards for dioxins/furans with work practice standards.

Response: See the preamble for discussion on dioxin/furan limits and detection limits.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 72

Comment: ACC supports the use of HCl as a surrogate for inorganic HAP. The justification for using HCl as a surrogate for inorganic HAP is similar to the justification for use of PM as a surrogate for non-mercury HAP metals, in that control technologies that would reduce HCl would also control other inorganic compounds that are acid gases.

Response: EPA acknowledges the comment and agrees. It has finalized HCl as a surrogate for non-metallic inorganic HAP in the final rule.

Other - Rationale for Regulated Pollutants

Commenter Name: Norbord Industries
Commenter Affiliation: Norbord Industries
Document Control Number: EPA-HQ-OAR-2002-0058-0854.1
Comment Excerpt Number: 4

Comment: How was a 10% opacity limit selected? There appears to be no clear explanation.

Response: Opacity is often required in CAA rules as a surrogate for PM to assure compliance with PM standards when continuous PM monitoring is not required under the applicable standard. The 10 percent operating limit is in the general range of other opacity limits for combustion rules.

Rationale for Subcategories

Subcategories: New Suggested Categories

Commenter Name: Houston Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1876
Comment Excerpt Number: 6

Comment: Establish an exclusive work practice or other approach for limited-use boilers.

Response: Please refer to the preamble for discussion of the limited use subcategory.

Commenter Name: Los Angeles Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1778
Comment Excerpt Number: 6

Comment: Our oil-fired boiler is used as an auxiliary or intermittent back-up boiler. It runs on reprocessed fuel oil also known as fire coal. And this oil is processed to meet Washington State designated specifications. Natural gas is not available in our area. The cost of the additional pollution control equipment is exorbitant when compared to the amount of pollutants that would be collected from this unit. This may lead us, ironically, to shut down our most modern boiler, run our other units harder and/or curtail our production.
The trickle-down effect includes having the fuel supplier having to decide whether or not it's worth it to continue processing the RFO if, indeed, it loses its biggest customer. This product was developed in conjunction with the state's need to provide a beneficial use for the oil and to get the used oil out of the storm drains and landfills around the state. This certainly would be an unfortunate unintended consequence from these rules.

Response: See the preamble for revisions made for limited use boilers.

Commenter Name: Houston Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1876
Comment Excerpt Number: 138

Comment: EPA needs to include further subcategorization to address small or limited-use units.

Response: Please refer to the preamble for discussion of the limited use subcategory.

Commenter Name: Houston Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1876
Comment Excerpt Number: 149

Comment: EPA should include further subcategorization to address small or limited use units.

Response: Please refer to the preamble for discussion of the limited use subcategory.

Commenter Name: John W. Fainter, Jr.
Commenter Affiliation: Association of Electric Companies of Texas
Document Control Number: EPA-HQ-OAR-2002-0058-2790.1
Comment Excerpt Number: 1

Comment: "Limited Use" Category for Certain Auxiliary Boilers

Electric utilities operating auxiliary boilers will be subject to the 1B MACT rule because they are not steam generating units that produce electricity. Auxiliary boilers operate infrequently; normally during plant startups and combust either natural gas or distillate fuel. As a result, the HAP emissions from the auxiliary boilers are exceedingly low and do not pose any risk to public health.

The proposed subcategories do not adequately account for the unique characteristics of these boilers. Under the proposed rule, gas-fired auxiliary boilers are subject to work practice standards requiring an annual tune up. By contrast, the IB MACT proposed rule requires auxiliary boilers combusting distillate fuel to comply with stringent emission limits and demonstrate compliance with those limits by following expensive monitoring requirements. The distinction between these two different types of auxiliary boilers is unnecessary and does not provide any additional environmental benefits.

EPA should create a limited use subcategory for boilers combusting distillate fuel that would subject those units to the same work practice standards as gas-fired units. The limited use subcategory should have a 10% capacity factor threshold. Eligibility for this subcategory would be determined based on 10% of the maximum hourly heat input of the boiler multiplied by 8760 hours per year.

Consideration of at "limited use" category is not a new approach. In Fact, the definition of "limited use" was included in EPA's original boiler MACT, 69 Fed. Reg. 55,268 (Sept. 13, 2004) (defining "limited use" subcategories to include boilers or process heaters with a rated capacity of greater than 10 MMBtu/hr and "a federally enforceable annual average capacity factor of equal to or less than 10 percent."). EPA should utilize its prior determinations and create a limited use subcategory for boilers combusting distillate fuel.

Without such a subcategory, the NESHAP would require a great deal of time and expense. In some cases, testing for the emissions could add 20 to 30%
to the total emissions for that boiler in a year. That is counterproductive to achieving emissions reductions.

Response: Please refer to the preamble for discussion of the limited use subcategory.

Commenter Name: JoAnne Rau
Commenter Affiliation: Dayton Power and Light Company
Document Control Number: EPA-HQ-OAR-2002-0058-2762.1
Comment Excerpt Number: 2

Comment: Develop standards that are more narrowly tailored to specific types of liquid fuels and types of boiler so as to reflect the differences in capabilities of different type boilers and the different constituents and concentrations of constituents within different fuels;

Response: See response to comment EPA-HQ-OAR-2002-0058-2987.1, excerpt 3 for general requests for additional subcategories.

Commenter Name: J. Michael Geers
Commenter Affiliation: Duke Energy
Document Control Number: EPA-HQ-OAR-2002-0058-2765.1
Comment Excerpt Number: 2

Comment: Duke Energy urges EPA to create a "limited use" category for existing fuel oil-fired auxiliary and plant heating industrial boilers that requires a work practice standard in lieu of an emission standard for major and area sources of HAP.
Many auxiliary and heating boilers at fossil and nuclear electric generation facilities and other industrial facilities have a maximum heat input capacity greater than 10 million Btu/hour and

burn natural gas and/or fuel oil. These units operate infrequently and then for only a limited amount of time to provide steam for startup of other sources, and/or power plant comfort heating during the winter outages when an electric generation unit is not operating. These types of auxiliary and heating boilers typically operate for less than 10% of the hours in a year (less than 876 hours per year). As a result, the HAP emissions from these boilers are exceedingly low and do not pose any risk to public health. EPA has proposed in the IB MACT rule that gas-fired auxiliary boilers will be subject to work practice standards that will require an annual tune up. By contrast, the proposed IB MACT rule would require oil-fired auxiliary boilers to comply with stringent emission limits and demonstrate compliance with those limits by following expensive monitoring requirements. The significant difference in the proposed regulatory requirements for these two types of auxiliary boilers is unnecessary and will not produce environmental benefits. Requiring work practice standards for oil-fired auxiliary boilers (similar to those allowed for existing natural gas ICI boilers) would effectively reduce emissions of HAP for this category of ICI boilers. Expensive ICI boiler replacements, reconstructions, and/or modifications to meet an emission standard will not deliver significant additional HAP reductions and the added expense cannot be justified.
EPA has the authority to create a limited use subcategory of industrial boilers that are operated infrequently because of their specialized nature and use. Section 112(d)(1) of the CAA, which mirrors earlier language found in CAA Section 111(b)(2), allows the Administrator the discretion to distinguish among “classes, types, and sizes of sources” in establishing MACT standards. Indeed EPA has previously created limited use subcategories under Section 112, such as the recent reciprocating internal combustion engine “(RICE”) MACT rule. EPA should exercise its authority to establish a “limited use” category for auxiliary and heating boilers that operate infrequently and only for a specialized use.

Response: Please refer to the preamble for discussion of the limited use subcategory.

Commenter Name: Chris M. Hobson
Commenter Affiliation: Southern Company
Document Control Number: EPA-HQ-OAR-2002-0058-2741.1
Comment Excerpt Number: 2

Comment: Southern Company’s subsidiaries own and operate (or are building) 3 natural gas-fired and 6 distillate oil-fired auxiliary boilers. These auxiliary boilers are used to generate the steam necessary to bring a main electric generating unit (EGU), either a combined cycle, a coal-fired, or a nuclear unit, on line. Since the auxiliary boilers are primarily used during unit startup, operation is generally very limited (e.g., some are limited to a 10% capacity factor, and others generally operate less than 500 hours per year). Operating time is lower for plants that have multiple units due to inter-steam piping among the units that allows one unit to be brought online utilizing the steam generated from another online unit. As a result of the limited operation, the HAP emissions from the auxiliary boilers are exceedingly low.

The auxiliary boilers are an integral part of Southern Company’s black-start plan. Black-start is the term used in the utility industry to mean the procedure of starting electric generating units with a partially or completely de-energized transmission system. Unlike automobiles which have a storage battery to aid in starting, power plants cannot start up without some electricity or steam or both available. In the unlikely event of a black-start, the auxiliary boilers would be crucial in restoring power to the grid quickly and efficiently. For emergency purposes, oil-fired auxiliary boilers also have the advantage over natural gas-fired auxiliary boilers of on-site fuel storage. In other words, oil-fired auxiliary boilers are not dependent on natural gas pipeline delivery of fuel, and therefore can use oil stored on-site, which obviously adds more robustness and energy security in such an event. Also, supercritical boilers require a steam supply for startup. Outside of black-start situations, supercritical units would require the use of an auxiliary boiler only if steam is not available from any other unit onsite. In addition to operating the auxiliary boilers for such events, the boilers may be operated periodically for short periods of time to ensure readiness and perform maintenance, generally 2 to 3 hours at a time and less than 10 total hours a month.

Under the proposed rule, gas-fired auxiliary boilers are subject to work practice standards requiring an annual boiler tune up, in lieu of stringent emission and monitoring requirements. Southern Company supports the use of work practice standards for such sources and urges EPA to maintain these requirements in its final rule. By contrast, the proposed IB MACT rule requires oil-fired auxiliary boilers to comply with stringent emission limits and demonstrate compliance with those limits by following expensive monitoring requirements. The distinction between these two different types of auxiliary boilers (gas-fired and oil-fired) is unnecessary and does not produce environmental benefits.

Because auxiliary boilers operate infrequently and only as needed, it will be difficult to perform emission testing. Additionally, since the demand for these boilers is almost impossible to forecast and generally lasts less than 24 hours per usage, we cannot reasonably schedule and assemble test crews and complete all of the required testing within that period. It will certainly be impossible to provide the 60 days notice required by 40 CFR 63 for testing to coincide with times the boilers would otherwise be in operation to provide backup steam for startup of the electric generating unit. Thus, it is likely that each auxiliary boiler would have to be operated each year for the sole purpose of emission testing. This would create unnecessary boiler operation, fuel usage, and emissions, with annual operating time increases of 50% to greater than 200%.

Southern Company recommends that EPA create a separate subcategory for limited use (i.e., less than or equal to10% capacity factor), oil-fired boilers and suggests that the work practice standard currently applied to gas-fired boilers (boiler tune-up) be applied in lieu of emissions standards.

Southern Company notes that the vacated IB-MACT rule contained several limited-use subcategories, including new/reconstructed limited use solid fuels, new/reconstructed limited use liquid fuels, new/reconstructed limited use gaseous fuels, and existing limited use solid fuel. [Footnote: Limited use subcategories were not necessary for existing gas and liquid fired units because EPA had determined that the MACT floor for these units was “no emissions reductions”.] The limited use subcategory in the vacated rule applied to sources with an annual capacity factor of 10% or less, such as auxiliary boilers at electric power plants. While EPA’s decision to provide emission floors of “no emissions reductions” may no longer be possible, it is possible to set work practice standards instead of emission limits for these sources.

Response: Please refer to the preamble for discussion of the limited use subcategory.

Commenter Name: Jacquelyn Taylor
Commenter Affiliation: South Carolina Pulp and Paper Association
Document Control Number: EPA-HQ-OAR-2002-0058-3154.1
Comment Excerpt Number: 2

Comment: An additional subcategory that EPA needs to establish is one for “limited use” units. Because limited use boilers do not operate on a regular schedule and typically operate for only short periods of time, emissions profiles for these boilers can vary significantly from those of a similar boiler operating in a steady state. A capacity utilization factor of 10% was chosen for the previous boiler MACT final rule as the best means of defining a limited use unit. This definition is equally appropriate for the current rule. Also, given the limited and sporadic operation of emergency and auxiliary boilers, as well as the technical infeasibility of imposing emission limitations on these units, the limited use subcategory should require
work practices in lieu of emission limits.

Response: Please refer to the preamble for discussion of the limited use subcategory.

Commenter Name: Winslow Sargeant
Commenter Affiliation: US Small Business Administration
Document Control Number: EPA-HQ-OAR-2002-0058-2916.1
Comment Excerpt Number: 3

Comment: EPA Should Have Adopted Additional Subcategories

SERs recommended that EPA adopt the following subcategories for boilers:

* Fuel type (including coal rank, bagasse, biomass by type, and oil by type);
* Boiler design type (e.g. fluidized bed, stoker, fuel cell, suspension burner);
* Duty cycle;
* Geographic location;
* Boiler size;
* Burner type (with and without low-NOx burners);
* Process heaters;
* Limited use boilers.
*

Subcategorization as outlined above was a primary flexibility concern of the SERs during the SBREFA panel. The panel report states that, “SERs commented that subcategorization is a key concept that could ensure that like boilers are compared with similar boilers so that MACT floors are more reasonable and could be achieved by all units within a subcategory using appropriate emission reduction strategies." [.SBAR Panel Report at 22.] While the Panel did recognize that the entire list of potential subcategorizations asked for by SERs was not practicable because of overlap in the categories, EPA should have proposed some additional subcategories as recommended by the panel. EPA has almost complete discretion to establish any subcategories "as appropriate". [Section 112(c)(1) of the Clean Air Act. EPA may distinguish among classes, types and sizes of sources within a category. House Report No. 101-490, Part 1 at 328.] Without the additional subcategories, it increase the cost and difficulty for many small sources to meet emissions standards when they are placed in a category that is driven by the efficiency of very different boiler units running on different fuels, under different duty cycles, and most likely designed for very different purposes. In many cases, forcing boilers into categories where they do not belong will require costly investments to meet standards that are simply not achievable for certain boiler and fuel types, while yielding small or insignificant environmental benefits. In particular, it is very hard to justify why limited use boilers should be subject to the same standards as other boilers. [This contrasts strongly with the treatment of the recent MACT standards adopted for limited use reciprocating diesel and spark ignition engines, promulgated by the Agency in 2010, creating a separate category for limited use engines and emergency use engines (e.g engines that run less than 24 hours per year). EPA does not explain the disparate treatment.] EPA did include a "limited use" subcategory for boilers with average capacity factors of 10% or less in the 2004 boiler rule.

Response: The EPA sees no technical or legal justification for creating separate subcategories for cyclone, firetube, and hybrid watertube-firetube boilers. EPA reviewed the database and identified that firetube boilers exist predominantly in both the biomass and liquid subcategories, and that the size of firetube boilers ranges widely, with most being between 0 and 50 mmBtu/hr but some of the firetube units were reported as large as 250 mmBtu/hr. Firetube boilers existing in many different affected sectors and several different boiler designs including stokers and dutch ovens.Given the wide variety of firetube boilers and the data available for the rulemaking, EPA determined it is inappropriate to further partition the database to account for firetube and non-firetube units in addition to subcategorizing according to combustor design. Further subcategorization by design type has been addressed in the final rule by establishing a combined grate/suspension firing subcategory. Please refer to the preamble for discussion of this category. See response to comment EPA-HA-OAR-2002-0058-2808.1, excerpt 12 for further subcategorization based on coal rank. Please refer to the preamble for discussion of the limited use subcategory. See response to comment EPA-HQ-OAR-2002-0058-1841.1, excerpt 2 for bagasse boiler subcategory. See response to comment EPA-HQ-OAR-2002-0058-3213.1, excerpt 148 for further subcategorization by fuel type. See response to comment EPA-HQ-OAR-2002-0058-2960.1, excerpt 61 for additional subcategory based on regional fuel availability or geographic location. See response to comment EPA-HQ-OAR-2002-0058-2818.1, excerpt 18 for subcategorizing according to heat input size. See response to comment EPA-HQ-OAR-2002-0058-2912, excerpt 2 for separate subcategories for process heaters and boilers. See response to comment EPA-HQ-OAR-2002-0059-2702.1, excerpt 68 for additional subcategory to distinguish between units with low NOx burners.

Commenter Name: John C. Hendricks
Commenter Affiliation: American Electric Power
Document Control Number: EPA-HQ-OAR-2002-0058-2703.1
Comment Excerpt Number: 3

Comment: EPA Should Consider a Limited Use Exemption. AEP utilizes its oil-fired industrial boilers sporadically for assisting in the start-up of an EGU or for plant heating in the winter. These boilers should be treated in a similar manner to the natural gas-fired units and be subject to work practice standards. A 10% capacity factor threshold should be considered for these types of situations.

A number of costly upgrades and retrofits would be required to comply with the proposed rule. The stacks would need to be retrofitted with platforms and access in order to meet Method 1 criteria and monitoring equipment to accommodate CO CEMS monitors as well as ports for the annual testing requirements. These costly burdens are for a fleet of industrial boilers that operate, on average, less than 300 hours per year.

In addition to preventing the necessity for costly upgrades to units that are used less than 10% of the year, the limited use exemption will lessen emissions caused by complying with the proposed rule. AEP's industrial boilers do not operate in a regular manner, therefore, AEP would have to schedule the boilers to operate additional hours, and thereby actually increase HAPs emissions, in order to complete the extensive yearly testing program. Conservatively, 10% of a boilers operation time may be forced by having to complete the testing requirements.

AEP strongly encourages the EPA to allow for a limited use exemption in the final rule.

Response: Please refer to the preamble for discussion of the limited use subcategory.

Commenter Name: Russ A. Wozniak
Commenter Affiliation: Dow Chemical Company
Document Control Number: EPA-HQ-OAR-2002-0058-2632.1
Comment Excerpt Number: 3

Comment: EPA Should Include a Limited Use Subcategory for Gaseous Fuels, Liquid Fuels, and Solid Fuels similar to the 2004 Version of the MACT rule. EPA should recognize and establish separate work practice requirements for boilers and heaters that are operated on a limited use basis. For example, Dow operates some process heaters to support certain processes only during periods of start-up by warming up heat transfer fluids to a desired temperature. In some cases, these heaters operate for a short period of time and in other cases these sources cycle on and off for a few hours in order to maintain the temperature of a process fluid above a certain point. These types of process heaters have an annual capacity factor of less than 10 percent and in some cases they operate for < 5% of the time and typically between 12 to 438 hours per year.

EPA's proposed rule for Gas 2 fuels creates significant challenges for these sources that only operate for a small number of hours per year. First, it will be impossible to conduct an annual performance test in many cases since the length of the performance test itself requires that the heater operate for ~ 24 hours in order to collect the 3, 4-hour test runs with time required before and between test runs. Second, it will be very difficult to conduct an annual tune-up of these sources that operate for only a limited period of time.

Response: Please refer to the preamble for discussion of the limited use subcategory.

Commenter Name: Michael J. Nasi
Commenter Affiliation: Gulf Coast Lignite Coalition
Document Control Number: EPA-HQ-OAR-2002-0058-2800.1
Comment Excerpt Number: 4

Comment: EPA should create a limited use subcategory for auxiliary boilers, similar to the previous Industrial Boiler NESHAP.

EUSGU auxiliary boilers operate during startup on an infrequent basis (10% or less a year), utilizing natural gas or distillate fuel. Recognizing that auxiliary boilers function differently than typical industrial, commercial, and institutional boilers, the EPA created a limited use subcategory in 2004 for boilers combusting distillate fuel. [Footnote: 69 Fed.Reg. 55,268 and 55,232 (Sept. 13, 2004). "Limited use units are those large units with capacity utilizations less than or equal to 10 percent…"]

Here the EPA is proposing strict emission standards and monitoring requirements for these boilers, which are seldom used, and including startup and shutdown emissions. HAP emissions from these boilers are relatively low and the imposition of an emission standard results in a cost in a cost that outweighs any environmental benefit. GCLC requests that EPA adhere to prior NESHAP promulgations for Industrial Boilers and create a limited use subcategory for boilers combusting distillate fuel.

Response: Please refer to the preamble for discussion of the limited use subcategory.

Commenter Name: Frank Kohlasch
Commenter Affiliation: Minnesota Pollution Control Agency
Document Control Number: EPA-HQ-OAR-2002-0058-2773.1
Comment Excerpt Number: 4

Comment: Create a subcategory for limited use boilers. Some boilers are used only for back-up of primary units that are not operating due to malfunction or maintenance. EPA should consider developing a category for "limited use boilers" that have a federally enforceable annual capacity factor equal to or less than ten percent, provided that the units are indeed backup units and not process units. This may avoid substantial investments in air pollution controls for back-up boilers, and instead address air quality impacts from these units as necessary to eomply with new hourly ambient air quality standards for SO2 and NOR.

Response: Please refer to the preamble for discussion of the limited use subcategory.

Commenter Name: Russ A. Wozniak
Commenter Affiliation: Dow Chemical Company
Document Control Number: EPA-HQ-OAR-2002-0058-2632.1
Comment Excerpt Number: 4

Comment: Dow has sites in which gas fired back-up boilers are kept in a warm and ready condition, but not fired. Industry calls these types of boilers "warm stand-by" boilers. Should the lower cost primary steam supplier have to go down, such as a cogeneration plant, these back-up boilers will quickly come on line to maintain steam supply. This arrangement provides reliable steam to the site while avoiding emissions by low firing of the back-up boiler. Such back-up boilers are typically fired less than 10% of the year. When such boilers are firing Gas 2 fuels, it will be very difficult to keep emissions below the proposed limits. Emissions are higher during startup and shutdown intervals than normal operation. The percent of time such boilers are in a startup or shutdown mode is much higher than for continuously operated boilers. These boilers also will not experience the benefit of 30 day emissions averaging as proposed in the rule.

Response: Please refer to the preamble for discussion of the limited use subcategory.

Commenter Name: Russ A. Wozniak
Commenter Affiliation: Dow Chemical Company
Document Control Number: EPA-HQ-OAR-2002-0058-2632.1
Comment Excerpt Number: 5

Comment: Dow supports the recordkeeping requirement that is proposed in Section 63.7555(d)(3) for limited-use boilers and process heaters. Dow further comments that this recordkeeping requirement should be the only requirement for these limited use combustion sources. The term limited-use boiler/process heater is not defined in this proposed rule. EPA should include the following definitions from the 2004 version of the MACT rule (with slight adjustments to include all types of boilers and heaters) into this final rule:

Annual capacity factor means the ratio between the actual heat input to a boiler or process heater from the fuels
burned during a calendar year, and the potential heat input to the boiler or process heater had it been operated for
8,760 hours during a year at the maximum steady state design heat input capacity.

Limited use gaseous fuel subcategory includes any boiler or process heater that burns gaseous fuels not combined with any liquid or solid fuels, burns liquid fuel only during periods of gas curtailment or gas supply emergencies, , and has a federally enforceable annual average capacity factor of equal to or less than 10 percent.

Limited use liquid fuel subcategory includes any boiler or process heater that does not burn any solid fuel
and burns any liquid fuel either alone or in combination with gaseous fuels, , and has a federally enforceable annual average capacity factor of equal to or less than 10 percent. Limited use gaseous fuel boilers and process heaters that burn liquid fuel during periods of gas curtailment or gas supply emergencies are not included in this definition.

Limited use solid fuel subcategory includes any boiler or process heater that burns any amount of solid
fuel either alone or in combination with liquid or gaseous fuels, and has a federally enforceable annual average capacity factor of equal to or less than 10 percent.

Response: Please refer to the preamble for discussion of the limited use subcategory.

Commenter Name: Wayne Smith
Commenter Affiliation: Westlake Chemical Corporation
Document Control Number: EPA-HQ-OAR-2002-0058-2785.1
Comment Excerpt Number: 6

Comment: Boilers and Process Heaters Consolidation: Boilers and Process Heaters are consolidated into single categories of affected units in the Proposed Rules. Boilers and Process Heaters are generally designed and operated for a very different purpose. Boilers are generally operated with a variable firing rate to accommodate changing steam demands. Process Heaters are generally operated with a steady state operation to maintain a steady state consistent process flow. The resultant Carbon Monoxide emissions will be significantly different between Boilers and Process Heaters. Boilers will generally have more Carbon Monoxide emissions and will be designed to handle fluctuating firing rates. Process Heaters are tuned to operate at steady state with minimal Carbon Monoxide emissions. The resultant organic HAP emissions from Boilers and Process Heaters at Major Sources will be minimal. The good combustion and residence time in the Boilers and Process Heaters will prevent the formation of organic HAP emissions, even with some Carbon Monoxide emissions.

Response: See response to comment EPA-HQ-OAR-2002-0058-2912, excerpt 2 for separate subcategories for process heaters and boilers.

Commenter Name: Sean M. O'Keefe

Commenter Affiliation: Alexander and Baldwin, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-3196
Comment Excerpt Number: 6

Comment: While biomass boilers as a group tend to emit higher levels of CO than coal-fired boilers for the reasons outlined above, there can also be considerable variation in emissions from boilers within the biomass subcategory, particularly from those burning fuels with relatively high moisture content (such as bagasse). In addition to fuel characteristics, however, boiler design and operational characteristics, as well as the manner in which the boiler is integrated into plant operations, can all contribute to significant variations in emissions profiles among biomass boilers.

Under the proposed rule, most bagasse-fired boilers would be categorized as "suspension burners/Dutch ovens designed to burn biomass" and would be subject to the corresponding proposed emissions limits, including a CO limit of 1,010 ppm (corrected to three percent oxygen). Importantly, this MACT floor appears to be driven largely by emissions data from units which fire dry biomass fuels and that are significantly different in design and operation from sugar mill boilers. Since the MACT emission standards applicable to any boiler are to be based upon the performance of "similar sources", A&B believes that this proposed CO limit is not appropriate for bagasse-fired boilers.

Response: See response to comment EPA-HQ-OAR-2002-0058-1841.1, excerpt 2 for bagasse boiler subcategory.

Commenter Name: Sean M. O'Keefe
Commenter Affiliation: Alexander and Baldwin, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-3196
Comment Excerpt Number: 7

Comment: As a result of their unique design and operational characteristics, emissions from bagasse-fired boilers, and particularly emissions of CO and particulate matter (PM), can vary considerably from those of other biomass-fired boilers. It is therefore appropriate to recognize these boilers as a distinct type or class of biomass-fired boiler and to establish a separate bagasse boiler subcategory, with its own corresponding MACT floors. A&B encourages EPA to establish a separate boiler subcategory for bagasse boilers in order to ensure that the emissions standards for these boilers are based on the performance of similar sources as required by the Clean Air Act.

Response: See response to comment EPA-HQ-OAR-2002-0058-1841.1, excerpt 2 for bagasse boiler subcategory.

Commenter Name: Debra J. Jezouit

Commenter Affiliation: Class of '85 Regulatory Response Group
Document Control Number: EPA-HQ-OAR-2002-0058-2802.1
Comment Excerpt Number: 7

Comment: EPA should establish a limited use subcategory for Boilers.

The Class of ‘85 strongly supports the creation of a limited use subcategory for Boilers. The CAA allows EPA to divide source categories into subcategories based on differences in class, type, or size. In past rulemakings, EPA has considered creating limited use subcategories as part of a NESHAP where the proposed standards for "normal" (i.e., non-limited use) sources (1) are impracticable because the measurement methodologies require continuous hours of operation; (2) would result in greater emissions because the limited use source would be required to operate substantially longer to meet a numeric emission standard; or (3) have limited effectiveness due to the short periods of time the sources typically operate. [Footnote: See, e.g., 75 Fed. Reg. 9648, 9662 (March 3, 2010) (establishing separate standards for black start units); 69 Fed. Reg. 33474, 33483 (June 15, 2004) (establishing a limited use subcategory for reciprocating internal combustion engines).] Based on these criteria, the Group believes that limited use boilers, such as auxiliary boilers operated at electric generating stations, are susceptible to subcategorization.

Electric generating stations frequently have auxiliary boilers that are used for supplying startup steam to an EGU. Auxiliary boilers are used sporadically, operated for short periods of time, have a limited capacity factor, and are often classified as a "major source" based solely on their location at a generating station. The infrequent operation of auxiliary boilers and their resulting minimal emissions make the application of pollution controls more difficult and costly than at a Boiler that is operated continuously and for extended periods of time. For example, the Proposed Rule would impose the following requirements on an auxiliary Boiler that operates an average of 131 hours per year:

Install, operate and maintain CO and oxygen continuous emissions monitoring systems ("CEMS") and a data acquisition and handling system.
Comply with CO standards on a 30-day rolling average basis.
Test annually for particulate matter ("PM") and dioxinlfuran, and potentially test annually for HC1 and mercury if compliance cannot be demonstrated through fuel-based methods. If it is assumed that compliance can be demonstrated through fuel-based methods, the Proposed Rule would require at least 15 hours of performance testing per year (three 1-hour PM runs and three 4-hour dioxinlfuran runs). If all testing for all pollutants is required, the test time increases to at least 24 hours per year (not including periods of startup and stabilization).

It would be extremely difficult for an auxiliary boiler to meet an emission standard based on a 30-day rolling average, and operating merely for the purposes of testing would result in an estimated 10-20% increase in the number of hours an auxiliary boiler operates per year. The proposed requirements are clearly impractical and excessive in light of the limited number of hours these relatively small boilers operate each year.

Response: Please refer to the preamble for discussion of the limited use subcategory.

Commenter Name: Pamela F. Faggert
Commenter Affiliation: Dominion
Document Control Number: EPA-HQ-OAR-2002-0058-2908.1
Comment Excerpt Number: 8

Comment: The proposed rule will affect many natural gas and distillate oil-fired auxiliary boilers within the electric utility industry. These auxiliary boilers are typically used to generate the steam necessary to bring a main electric generating unit (EGU) on line (during startup). Since auxiliary boilers are primarily operated during unit startup, operation for many of these boilers is typically very limited (e.g., on the order of 500 operating hours or less in a calendar year).

For units with such limited operation, work practice standards that EPA has proposed for units that burn natural gas would be more appropriate, feasible and much less costly. The proposed emission limits and compliance provisions for large (>10 mmBtu/hr) limited use boilers that burn distillate oil are unreasonable. The cost for sources with oil-fired auxiliary boilers to install and maintain the control equipment (and potentially monitoring equipment) necessary to meet the proposed emissions standards would be excessive, particularly for a unit that operates infrequently. In addition, since the demand for an auxiliary boiler to operate is very difficult to forecast, it is almost a certainty that each auxiliary boiler would have to be operated some time during each year for the sole purpose of emission testing. Such an outcome would result in otherwise unnecessary emissions of air pollutants and use of a valuable and not unlimited resource (low sulfur diesel fuel). For these reasons, we recommend that EPA create a separate subcategory for limited use, oil-fired boilers and suggest that the work practice standard proposed for gas-fired boilers be applied in lieu of emissions standards. The limited use subcategory should have the 10% capacity factor threshold that EPA applied in the previous (now vacated) Industrial Boiler MACT rule for several limited-use subcategories, including new/reconstructed limited use solid fuels, new/reconstructed limited use liquid fuels, and new/reconstructed limited use gaseous fuels, and existing limited use solid fuel. While EPA embraced the use of limited-use subcategories in the vacated rule, it has not provided any justification for eliminating these subcategories in the proposed rule. To the extent emission limits are retained for limited-use units, annual testing requirements should be eliminated and a more flexible testing schedule should be provided that would not require the operation of these units for the sole purpose of testing.

Response: Please refer to the preamble for discussion of the limited use subcategory.

Commenter Name: Randy Stoeckel
Commenter Affiliation: Johnson Timber Corporation
Document Control Number: EPA-HQ-OAR-2002-0058-1975.1
Comment Excerpt Number: 1

Comment: We operate a 10 million BTU per hour biomass boiler for approximately 130 days out of the year with only 40% of those operating days at 10 million BTUs per hour yet under the current Boiler MACT regulations we would be under the same restrictions as much larger boilers operating 365 days a year at full load. In today's economy with high unemployment, house foreclosures and a shrinking manufacturing job market, mills like ours are more important than ever and Boiler MACT in its current form puts us at great risk.

Boiler MACT under its current structure accomplishes too little for the investment required. I do not disagree that we should strive for continuous improvement but it must be done within a framework of affordability with common sense attainable goals. Under the current rules a boiler which operates 130 days / year or 14 days / year is under the same emission limits as boilers operated 365 days yet the investment could very well be the same to meet the new guidelines. The economics make it nearly impossible to justify the small impact our reduction would make to the environment. There comes a point of diminishing returns that do not appear to be justifiable. I support clean air and clean water but there are limits that struggling industries can afford.

Response: Please refer to the preamble for discussion of the limited use subcategory.

Commenter Name: David A. Buff
Commenter Affiliation: Golder Associates
Document Control Number: EPA-HQ-OAR-2002-0058-1841.1
Comment Excerpt Number: 2

Comment: Bagasse is produced in a sugar mill as a result of sugar being extracted from sugarcane. Bagasse is the wet fibrous material remaining after the sugarcane has been cut, ground, and repeatedly washed and pressed to recover as much sucrose as possible. Since the very beginning of its operations in the United States, the sugar producing industry has used bagasse as the primary fuel for its boilers. Bagasse boilers are specifically designed to dry and burn the bagasse in the furnace, and the boilers are wholly integrated into the operations of the sugar mills. As bagasse is produced in the sugarcane milling/grinding process, it is fed directly into the boilers, where the bagasse is dried and burned. In a typical integrated sugar mill, the burning of the bagasse generates enough heat to produce the steam and electricity needed to power the operation of the sugar mills. [See submittal for the detailed flow diagram in the foldout drawing and in Figure 1.]

Bagasse boilers exhibit several distinctive design, operating, and emission characteristics when burning bagasse. These characteristics can be summarized as follows:
(a) Bagasse boilers are uniquely designed and operated to burn bagasse
(b) Bagasse boilers are fully integrated with the sugar mill and the other boilers at the mill
(c) Bagasse is fed directly and continuously from the sugar mills to the boilers
(d) Bagasse is a unique fuel generated by an industrial process, with high moisture content, low density, wide range of particle sizes, and other unique characteristics

When these characteristics are considered together, it is clear that bagasse boilers constitute a unique class of industrial boilers. Consequently, bagasse boilers should be regulated in a separate subcategory under the revised Boiler MACT rules. This subcategory should not include other types or classes of boilers (e.g., boilers that burn other types of biomass or fossil fuel).

Many times in the past, EPA has created various subcategories in rulemaking under the Clean Air Act (CAA) because EPA has recognized that a facility's emissions can be significantly affected by the facility's fuel, design, size, age, and use. When establishing the upcoming Boiler MACT rules, EPA has the statutory authority pursuant to Section 112 of the CAA to create subcategories based on "classes, types, or sizes" of industrial boilers. Indeed, EPA has created several industrial boiler subcategories in the proposed Industrial Boiler MACT rule published on June 4, 2010.

EPA should create a subcategory for bagasse boilers because they constitute a distinct class and type of boiler. Their design and operation sets them apart from other solid fuel and biomass-fueled boilers. Their unique characteristics significantly affect the boilers? emissions. Bagasse also has distinctive fuel characteristics that affect the boilers? emissions. Creating a subcategory for bagasse boilers, based on the class or type of boiler, or fuel type, will help ensure that the MACT emissions standards for bagasse boilers are based on the performance of "similar sources," as required by the CAA. Conversely, EPA would not be able to establish an appropriate MACT floor for bagasse-fired boilers if bagasse boilers were regulated in a MACT category that includes other types or classes of solid fuel-fired or biomass-fired boilers.

2.0 BACKGROUND INFORMATION ON SUGARCANE AND SUGARCANE PROCESSING

The following discussion summarizes some basic information about sugarcane, sugarcane processing, bagasse, and bagasse boilers. Sugarcane is a member of the grass family, and is grown in numerous countries around the world, including the United States, China, India, Cuba, Venezuela, Indonesia, Australia, and many more. The cane grows year round, but typically the harvesting and milling operations occur over just a few months. In the U.S., the sugar mills typically run 24 hours per day during the milling season. The milling operations usually are completed in 4 to 6 months in Florida and Texas, and 9 months in Hawaii.
The tops and most of the leaves of the sugarcane plants are removed in the field and then the cane is brought to the mills in large trailers by truck or railcar. The typical composition of the sugarcane is presented in Table 1. [See Submittal for Table 1]

In the sugar mill, the cane is first cut into smaller pieces.[In Hawaii, but not Florida, the cane is washed in a cane "cleaner" prior to cutting. The cleaner is used to remove some of the extraneous soil that adheres to the cane when it is brought in from the fields.] Next, the sugarcane is subjected to grinding and washing, which is repeated from 4 to 8 times in a sugar mill "tandem." This process extracts as much of the sugarcane juices (primarily sucrose) as possible from the cane. This process also removes some, but not all, of the soil that may be clinging to the cane (carried in from the fields). The sugarcane juices are then clarified and evaporated to produce raw sugar crystals. Refer to the flow diagram in the foldout diagram and Figure 1.

Bagasse is the traditional name given to the cellulosic fiber and pith that remain after the sucrose juice has been extracted from a sugarcane stalk during the milling process. The composition of the biomass is changed in this process of producing bagasse from sugarcane. The typical composition of bagasses is shown in Table 2. [See submittal for Table 2]

The heat needed to operate the evaporators in the sugar production process, and the power (steam and electrical) needed to operate the mill equipment, are obtained by burning the bagasse in boilers that are specifically designed for the simultaneous drying and combustion of bagasse. The design of a sugar mill always includes the complete integration of the bagasse-burning boilers with the rest of the mill. The bagasse generated in the mill is normally sent directly to the boilers as fuel. The boilers produce steam, which in turn is used in the milling tandems (high pressure) and in the raw sugar production process (low pressure). The steam also is used in steam turbine generators to produce electricity for the mill's internal consumption. In some locations, excess electricity is fed back into the local power grid.

3.0 DESIGN AND OPERATION OF BAGASSE BOILERS

The design and operation of bagasse boilers differ significantly from other solid fuel and biomass-fired boilers. First, because bagasse contains between 48 percent and 55 percent moisture, it must be dried before it can be burned. This is accomplished in boilers specifically designed for this task. Secondly, bagasse fuel is low density and encompasses a wide range of particle sizes. A typical sample of bagasse has particle dimensions ranging from less than 100 micrometers up to a few centimeters, which is much different than the wood fired in boilers. The boilers must have specially designed feeders to spread the bagasse across the boiler.

The bagasse typically is conveyed directly and continuously from the mill to the boiler and then is dropped into chutes and fed into the boilers by means of fuel distributors. Air distributors located immediately below the fuel distributors inject air at the point where the bagasse is introduced into the boiler in order to spread the bagasse over the boiler width and length. The drying (and much of the combustion) occurs while the material is suspended in air. Hence, they are often called "suspension" boilers. However, due to the wide range of particle size and the high moisture content of the bagasse fuel, some of the bagasse is not burned completely and falls to the grate or floor below, where the combustion is completed.
Accordingly, many bagasse boilers have grates of various types, which allow additional air to mix with the fuel and thus enhance the combustion. For this reason, many bagasse boilers can also be called "stoker" boilers. In reality, bagasse boilers utilize a combination of suspension firing and grate firing, and that affects the performance of the boilers. Bagasse boilers are almost universally designed to have high furnace heat release rates [all except one bagasse boiler has a furnace heat release rate greater than 22,800 British thermal units per hour per cubic foot of furnace volume (Btu/hr-ft3)]. These high heat release rates are needed to quickly dry the wet bagasse as it is blown into the boilers. Despite the high heat release rates, the combustion temperatures are considerably lower than in other classes of boilers, due mainly to the high moisture content of the fuel.

The high heat release rates means shorter residence times for flue gases. Consequently, even though bagasse is a very clean fuel with respect to metals, sulfur, and chlorine, the wet bagasse and the shorter residence times in the boiler result in an incomplete burn out of carbon monoxide (CO). As a result of these factors, the concentrations of CO in the furnace gases can be very high in comparison with the CO emissions from other classes of boilers. Conversely, the lower temperature in the furnace results in significantly lower nitrogen oxides (NO_x) emissions compared with other classes of boilers.

The variety of sugarcane entering the mill fluctuates frequently, which causes the bagasse characteristics to fluctuate in turn. Different sugarcane varieties can cause differences in bagasse particle size, moisture content, and other fuel constituents. Different varieties are grown on different types of land, such as muck or sand lands. These differing soil types affect the amount and constituents of soil that enter the sugar mill with the sugarcane. Harvesting techniques and weather conditions (i.e., rainy or wet weather) can also affect the amount of soil brought in with the sugarcane, as well as the moisture content. Although the sugarcane undergoes a washing process to become bagasse, all of these variables lead to variability in the bagasse fuel characteristics. These in turn continually affect the combustion process in the boilers.

Normally, bagasse generated in the mill is fed directly to the boilers, without any intermediate storage. No blending or further processing of the bagasse takes place prior to combustion in the boilers. This characteristic of bagasse boilers differs from other biomass-fired boilers. Because the boilers receive the bagasse as it is produced, the performance of the boilers can be adversely affected when there is variability in the moisture content, particle size distribution, or other characteristics of the bagasse being produced by the sugar mill. Since the bagasse fuel characteristics often fluctuate significantly, particularly moisture content, there often is considerable variability (minute-to-minute and hour-to-hour) in the CO concentrations and emissions from bagasse boilers. Various authors have studied the effects of these combustion characteristics on bagasse boilers, and in particular CO emissions, as presented in Section 6.0.

All of the mill's boilers are tied into a single steam header, which provides high-pressure steam to the sugar mill tandems that grind the sugarcane. The integrated operations of the boilers and the sugar mill tandems is a unique feature of sugar mills. High-pressure steam is also provided to steam turbine electrical generators, and low pressure steam is provided to the raw sugar manufacturing process.

Because all of the operations are integrated (i.e., linked together), the boilers' emission rates are affected by mill steam demand, mill upsets, startups/shutdowns, and other events occurring in the mills that affect steam consumption and affect the steam load on the boilers. Operating conditions in one boiler can also adversely affect the other boilers, again due to the effect on steam demand.

Section 6.0 contains additional technical information concerning the unique design features of bagasse boilers. Section 6.0 also contains additional technical information comparing bagasse boilers to wood- fired boilers. This information further demonstrates the significant differences between bagasse boilers and other biomass and wood-fired boilers.

4.0 EPA'S STATUTORY AUTHORITY TO CREATE SUBCATEGORIES

Section 112 of the CAA contains the statutory requirements for establishing emission standards for industrial boilers based on the use of maximum achievable control technology (MACT). Section 112(d)(1) of the CAA expressly authorizes EPA to establish subcategories:
The [EPA] Administrator shall promulgate regulations establishing emission standards for each category or subcategory of major sources…The Administrator may distinguish among classes, types, and sizes of sources within a category or subcategory in establishing such standards…

Section 129 of the CAA also authorizes EPA to distinguish between classes, types, and sizes of units when setting MACT standards for incinerators. When construing Section 129, the U.S. Court of Appeals noted that EPA has "broad discretion to differentiate among units in a category" while setting MACT standards. Northeast Maryland Waste Disposal Authority v. EPA, 358 F.3d 936, 946 (D.C. Cir. 2004). The court concluded that the term "class" is "not defined in the Clean Air Act, and the dictionary definition – „a group, set, or kind marked by common attributes' – could hardly be more flexible." Id. The court's analysis implies that EPA may reasonably establish subcategories based on a "class" whenever EPA finds that there is a "group, set, or kind" of unit (boiler, incinerator, etc.) marked by common attributes.
EPA has exercised its discretionary authority to create subcategories in many prior MACT rulemaking proceedings. For example, EPA previously created subcategories when EPA set the MACT emissions standards for industrial boilers, electric utility steam generating units, and municipal waste combustors.
EPA created these subcategories because EPA wanted to account for the differences between source types, the types of fuel used, the size of the regulated units, and other factors. In EPA's "Notice of
Regulatory Finding on the Emissions of Hazardous Air Pollutants from Electric Utility Steam Generating
Units" [Federal Register (FR), December 20, 2000], EPA stated:
In developing standards under Section 112(d) to date, the EPA has based subcategorization on considerations such as: the size of the facility, the type of fuel used at the facility, and the plant type. The EPA may also consider other relevant factors such as geographic conditions in establishing subcategories.
In EPA's 2004 MACT proposal for electric utility steam generating units (Utility MACT) (FR, January 30,
2004), EPA stated that it has broad discretion to create subcategories based on these same criteria (i.e., size of the facility, type of fuel used, and plant type) [p. 4664]. In addition, "EPA also is free to consider other relevant factors, such as geographic factors, process design or operation, variations in emission profiles, or differences in the feasibility of application of control." [p. 4664]. In the Utility MACT,
EPA exercised its discretion by proposing to create five separate subcategories for coal-fired electric utility boilers [p. 4666]. Four of the proposed subcategories were based on the type of coal burned
(i.e., bituminous/anthracite, sub-bituminous, lignite, and coal refuse). The fifth subcategory was based on the type of process used by the utility to convert coal into electricity (i.e., integrated gasification combined cycle technology).
In EPA's 2008 MACT proposal for mercury cell chlor-alkali plants (73 FR 33258; June 11, 2008), EPA noted that "EPA's broad authority to establish categories and subcategories of

industry sources is firmly established, and has been recognized as entitled to substantial deference by the U.S. Court of Appeals for the D.C. Circuit and the U.S. Supreme Court." [p. 33273]. In defense of its decision to create a subcategory for mercury cell chlor-alkali plants, EPA stated that "we have a long history of using subcategorization….

Subcategories, or subsets of similar emission sources within a source category, may be defined if technical differences in emissions characteristics, processes, control device applicability, or opportunities for pollution prevention exist within the source category. This policy is supported by Section 112(d)(1), the legislative history, our prior rulemakings, and judicial precedent." (emphasis added) [Id.]

Most recently in EPA's 2010 MACT proposal for industrial boilers (FR, June 4, 2010), EPA stated that the

CAA allows EPA to divide source categories into subcategories based on differences in class, type or size

[p. 32016]. EPA states:

For example, differences between given types of units can lead to corresponding differences in the nature of emissions and the technical feasibility of applying emission control techniques. The design, operating, and emissions information that EPA has reviewed indicates differences in unit design that distinguish different types of boilers. Data indicate that there are significantdesign and operational differences between units that burn coal, biomass, liquid, and gaseous fuels. Boiler systems are designed for specific fuel types and will encounter problems if a fuel with characteristics other than those originally specified is fired…. The design of the boiler or process heater, which is dependent in part on the type of fuel being burned, impacts the degree of combustion. Boilers and process heaters emit a number of different types of HAP emissions. Organic HAP are formed from incomplete combustion and are influenced by the design and operation of the unit. The degree of combustion may be greatly influenced by three general factors: Time, turbulence, and temperature. Within the basic unit types there are different designs and combustion systems that, while having a minor effect on fuel-related HAP emissions, have a much larger effect on organic HAP emissions. Therefore, we decided to further subcategorize based on these different unit designs but only in proposing standards for organic HAP emissions.

EPA has previously used criteria such as furnace heat release rate in developing New Source Performance Standards (NSPS) subcategories for boilers. For example, Title 40, Part 60 of the Code of Federal Regulations (40 CFR 60), Subpart Db, contains separate NO_x limits for low heat release rate boilers and high heat release rate boilers burning fuel oil. For purposes of Subpart Db, a high heat release rate is defined as greater than 70,000 Btu/hr-ft3 and a low heat release rate as less than or equal to 70,000 Btu/hr-ft3.

Another example of EPA using subcategories to set emission standards involved the NSPS for municipal waste combustors (MWCs) in 40 CFR 60, Subpart Ea. In this rulemaking, EPA set new standards for two categories of MWC unit types. In the 1995 emission guidelines, EPA identified three distinct types of MWC units that burn refuse-derived fuel (RDF), as follows: (1) RDF stoker, (2) pulverized coal/RDF mixed fuel-fired combustor, and (3) spreader stoker coal/RDF mixed fuel-fired combustor. Recently, EPA identified two additional types of RDF-fired MWC designs that do not fit within the three types of RDF combustors defined in the regulations. Since none of the three previous subcategories of RDF municipal waste combustors correctly describe the design or operation of these particular units, EPA recognized a need to add combustor types that would adequately describe and set CO emission limits for these

combustors. The EPA therefore added definitions for “spreader stoker RDF-fired combustor/100 percent coal capable” and “semi-suspension RDF-fired combustor/wet RDF process conversion.” This latter subcategory was defined as follows:
Semi-suspension refuse-derived fuel-fired combustor/wet refuse-derived fuel process conversion means a combustion unit that was converted from a wet refuse-derived fuel process to a dry refuse-derived fuel process, and because of con

Response: Please refer to the preamble for discussion of a combined grate/suspension firing subcategory. This subcategory includes bagasse units however is based on design features, and is not specific to fuel type. Bagasse boilers that have a fuel cell combustor design will be covered under the fuel cell category,

See response to comment EPA-HQ-OAR-2002-0058-2987.1, excerpt 3 for general requests for additional subcategories.

Commenter Name: Arlington Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1779
Comment Excerpt Number: 5

Comment: Finally, some boilers are used for limited periods of time for back-up and should be treated differently than boilers running day in and day out.

Response: Please refer to the preamble for discussion of the limited use subcategory.

Commenter Name: Arlington Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1779
Comment Excerpt Number: 59

Comment: EPA can mitigate this burden OF two regulations on EGUS by establishing a separate subcategory for small municipal utilities and setting a compliance schedule for us that is consistent with the schedule for large investor-owned utilities to comply with the Utility MACT.

Response: See response to comment EPA-HQ-OAR-2002-0058-2795.1, excerpt 1 for additional subcategory for small municipal utilities or subcategorizing according to sector.

Commenter Name: Arlington Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1779
Comment Excerpt Number: 63

Comment: The Clean Air Act also provides EPA with broad discretion to subcategorize within the Boiler source category based on size, type, and class of source to help ensure that the emission limits are determined by the best performing similar sources and that the emission standard can be ultimately achieved in practice.

Then within the proper subcategory, EPA has the discretion to use a method for setting emission standards based on what real world best performing units actually achieve so that the units setting the bar for the rest of the subcategory will not have additional emission control obligations.

If the EPA were to use the discretion provided in the Clean Air Act, it could significantly alleviate the burden of this rule without compromising the environmental benefits that Congress intended. Flexible approaches in the Boiler MACT rule that appropriately address the diversity of units, operations, sectors, and fuels could prevent severe job losses and billions of dollars in unnecessary regulatory costs.

Response: See response to comment EPA-HQ-OAR-2002-0058-3213.1, excerpt 145 for EPA's authority to create subcategories.

Commenter Name: John Williams
Commenter Affiliation: Maine Pulp and Paper Association
Document Control Number: EPA-HQ-OAR-2002-0058-1913.1
Comment Excerpt Number: 6

Comment: Back-up Boilers. The proposed rule does not include a subcategory for limited use units or a de minimis applicability threshold for small/limited use units.

A number of the Maine Mills operate liquid and/or gaseous fossil fuel-fired unit that operate at a 10% annual capacity factor or less. These units typically operate only when the primary units are down due to malfunction or maintenance (e.g., annual mill outages). Many of the events that trigger the need to operate the back-up units are unpredictable. For example, AF&PA estimates that it will cost $10 million to upgrade a relatively small package boiler used primarily during mill shutdowns and to start up the Mill's primary boilers. This is a huge capital investment for very little environmental improvement. These standby boilers should be treated differently than boilers that run all year. It is simply not cost effective to install multi-million dollar add-on pollution control (such as an Electrostatic Precipitator) for a source that operates at 10% capacity or less annually. It would also be difficult to meet the testing requirements for these units. The Mills would likely have to schedule testing and operate the boilers only for the purpose of testing, even if they are not needed from an operational standpoint. Such an approach is not desirable from an environmental or business perspective.

Response: Please refer to the preamble for discussion of the limited use subcategory.

Commenter Name: Myra H. Glover
Commenter Affiliation: Entergy Services, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2757.1
Comment Excerpt Number: 1

Comment: Entergy Services, Inc. strongly supports the creation of a limited use subcategory for electric generating stations auxiliary boilers that are used for supplying startup steam. These EGU auxiliary boilers typically operate for short periods of time, have limited capacity factors, and are often classified as "major sources" based solely on their location at a generating station. The infrequent operation of auxiliary boilers results in minimal emissions and makes the application of pollution controls and other requirements of the proposed regulation impractical.

It would be extremely difficult for an auxiliary boiler to meet an emission standard based on a 30-day rolling average since they do not run for an extended time period. In addition, operating merely for the purposes of testing would result in an estimated 10-20% increase in the number of hours an auxiliary boiler operates per year and would result in a corresponding increase in actual emissions. The proposed requirements are clearly impractical and excessive in light of the limited number of hours these relatively small boilers operate each year. Thus, Entergy recommends establishing a "limited use" subcategory for auxiliary boilers operating no more than 500 hours per year. This subcategory should be exempted from the requirements of the Proposed Rule except for reasonable recordkeeping requirements aimed at demonstrating annual operating hours.

Response: Please refer to the preamble for discussion of the limited use subcategory.

Commenter Name: Eric Bakken
Commenter Affiliation: Tucson Electric Power Company
Document Control Number: EPA-HQ-OAR-2002-0058-2726.1
Comment Excerpt Number: 1

Comment: TEP believes EPA's approach for establishing MACT standards for auxiliary boilers is unnecessary and may actually have the unintended consequence of increasing emissions for the following reasons:

Due to the extremely limited use of these boilers (in TEP's case less than 0.1- percent of maximum annual heat input), hazardous air pollutant emissions from these boilers do not pose a threat to human health or the environment.

The cost to comply with the standards proposed by EPA would be excessive for these boilers especially when calculated on a "$/ton of pollutant removed" basis, again because of the limited use. While TEP has not conducted a detailed cost analysis, it is reasonable to conclude that for a facility regulated by the proposal, that operates for five hours or less, the cost associated with controlling the limited emissions from such a facility is not justifiable.

Demonstrating compliance with an emission standard through stack testing, or performing an annual tune-up to comply with the work practice standard would in our case require us to operate our auxiliary boilers more than we would otherwise, thereby resulting in more HAP emissions than would occur without a standard. EPA recognized the nonsensical nature of such a requirement by affirming in the proposed rule that “It would be inconsistent with the emission reductions goals of the CAA, and of section 112 in particular, to adopt requirements that would result in an overall increase in HAP emissions” [75 FR 32025].

CAA 112(h)(1) allows the EPA to establish a “design, equipment, work practice, or operational standard, or combination thereof” if in its judgment it is not feasible to prescribe and enforce an emission standard. For the reasons noted above, TEP believes that such an approach is appropriate for auxiliary boilers regardless of the fuel they burn. Due to the range of operating hours for limited use boilers, EPA should establish separate subcategories for limited use boilers, and set MACT standards for such equipment using the provisions of §112(d)(4), when appropriate. UARG, in their comments, provided the legal and rational basis under which EPA can and should create subcategories for limited use boilers, and use §112(d)(4) when appropriate. TEP believes that if EPA undertook a §112(h)(1) approach, they would conclude that the appropriate standard for limited use boilers approaching 10-percent of maximum annual heat input is a work practice for all fuel types as suggested in UARG’s comments.

However, for very limited use boilers (those whose heat input is less than 1-percent of the annual maximum) even an annual tune-up is not appropriate as pointed out above. For such very limited use boilers, EPA should establish a standard with no additional controls or requirements, other than monitoring annual hours of operation.

Response: Please refer to the preamble for discussion of the limited use subcategory.

Commenter Name: Robert Klemans
Commenter Affiliation: Florida Electric Power Coordinating Group Environmental Committee
Document Control Number: EPA-HQ-OAR-2002-0058-2733.1
Comment Excerpt Number: 4

Comment: EPA Should Consider Other Subcategories for Industrial Boilers, Such As Utility Auxiliary Boilers .Section 112(d)(1) of the CAA allows the Administrator to distinguish among "classes, types, and sizes of sources" in establishing MACT standards. In providing EPA discretion to create subcategories, §112(d)(1) does not restrict subcategorization to cases where the "class", "type" or "size" factors affected HAP emissions. The provision merely requires EPA to establish regulations for each category or subcategory on the schedules set out in § 112. FCG appreciates EPA’s effort to create several subcategories in the proposed IB MACT rule. However, EPA should have created additional subcategories. A limited use subcategory should be created for lBs that are operated infrequently or at low capacity because of their specialized nature and use.

FCG members operate at least 6 natural gas-fired and 2 oil-fired auxiliary boilers that will be subject to the IB MACT rule because they are not steam generating units that produce electricity. These auxiliary boilers operate infrequently or in a warm standby mode and are used for startup and emergency operations to support the larger electric utility generating units. As a result, the HAP emissions from these auxiliary boilers are very low.

Under the proposed rule, the natural gas-fired auxiliary boilers are subject to work practice standards requiring an annual tune up. By contrast, the proposed IB MACT rule requires oil-fired auxiliary boilers to comply with stringent emission limits and demonstrate compliance with those limits by following expensive monitoring requirements. The distinction between these two different types of auxiliary boilers is unnecessary and does not produce environmental benefits.

FCG urges EPA to exempt these operations or create a limited use subcategory for auxiliary boilers subject only to limited work practice standards. The limited use subcategory could have a 10% capacity factor threshold based on 10% of the maximum hourly heat input of the boiler multiplied by 8760 hours per year. Alternatively, distillate oil-fired boilers that operate in a warm standby mode at less than 10mmBtu/hour a majority of the time would also be subject only to work practice standards.

Response: Please refer to the preamble for discussion of the limited use subcategory.

Commenter Name: G. Vinson Hellwig and Robert H. Colby
Commenter Affiliation: National Assocation of Clean Air Agencies
Document Control Number: EPA-HQ-OAR-2002-0058-2841.1
Comment Excerpt Number: 4

Comment: The level of emissions of HAPs anticipated from well-performing units will differ substantially depending on the fuel that is being combusted. Accordingly, NACAA agrees that the large subcategories identified by EPA in its ICI Boiler MACT proposal – coal-fired, biomass-fired, liquid-fired and gas-fired – are reasonable and warranted by the differences in technology and expected performance, given the nature of the fuel consumed. EPA acknowledges that the properties of the fuel being combusted contribute significantly to the level of HAP emissions.["[B]ased on recently obtained information, we now understand that factors other than the controls (e.g., waste mix and combustion conditions) affect HMIWI performance, and those emission reduction strategies must be accounted for in MACT floor determinations." 73 Fed. Reg. at 72,970, 72,975. See also 74 Fed. Reg. at 51,377-79] However, the proposed rules fail to properly address this fundamental point in several important ways.

Response: See response to comment EPA-HQ-OAR-2002-0058-3213.1, excerpt 148 for further subcategorization by fuel type.

See response to comment EPA-HQ-OAR-2002-0058-3213.1, excerpt 145 for EPA’s authority to create subcategories.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 5

Comment: Industrial boilers should not be regulated in the same manner as electric utility boilers because of the differences in boiler size, fuel mix, application, design, operation, and the higher relative cost of emissions control. Although industrial boilers far outnumber electric utility boilers, industrial boilers produce a fraction of the steam that utility boilers produce and consume a fraction of the amount of fossil fuels that utility boilers consume. Industrial boilers also use their fuel more efficiently than utility boilers when the boilers produce both heat and power to support mill operations and do not experience the line losses that happen when electricity is transferred to utility customers. Industrial boilers in our industry also experience frequent load swings over the course of an operating day that utility boilers do not typically experience, and they typically burn more variable fuel types than utility boilers.

Response: See response to comment EPA-HQ-OAR-2002-0058-2795.1, excerpt 1 for additional subcategory for small municipal utilities or subcategorizing according to sector.

Commenter Name: Theresa Pugh
Commenter Affiliation: American Public Power Association
Document Control Number: EPA-HQ-OAR-2002-0058-2714.1
Comment Excerpt Number: 5

Comment: APPA also asks that EPA retain the limited use subcategory as finalized in the 2004 Boiler MACT rule. The D.C. Circuit Court decision vacating the 2004 rule did not undermine the justification set forth by EPA in support of a limited use subcategory. APPA members operate boilers in varying configurations, with some electric generating units used to backup primary units to ensure reliable electricity generation at all times. These backup units typically operate less than 10% of the time and in response to the scheduled and unscheduled downtime for primary units. These units may also be part of the standby capacity of a transmission network that must be reliably available to support the electric grid when need is determined by the transmission operator. These units must be operated periodically to ensure they will be reliably available upon demand to support the grid. APPA encourages EPA to adopt a limited use subcategory and/or exemptions that acknowledge the unique challenges associated with monitoring and measuring emissions from these sources. For instance, these units spend a considerable percentage of their time in periods of startup and shutdown during which control devices and/or monitoring equipment are not available or reliable. Compliance with the full-use MACT standard is not feasible for these units during these rapid and often unpredictable startup modes.

Response: Please refer to the preamble for discussion of the limited use subcategory.

Commenter Name: Sharene Shealey
Commenter Affiliation: RRI Energy
Document Control Number: EPA-HQ-OAR-2002-0058-2759.1
Comment Excerpt Number: 9

Comment: In the document, "Regulatory Impact Analysis: National Emission Standards for Hazardous Air Pollutants for Industrial, commercial, and Institutional Boilers and Process Heaters – Draft (April 2010)," EPA does not address the impact of the proposed rules on the electric generating industry. Electric generating stations frequently have process (i.e., non-EGU) boilers used for supplying start-up steam. In many cases, because these units are sporadically used and have capacity factor limits, they are only identified as major sources due to their location at the EGU facility. Emissions from these units in the context of a power generating station are minimal. The proposed rule will have a large impact on the ability to operate these relatively small sources. The below table shows 2009 reported emissions from the electric generating unit (boiler) at Cheswick Generating Station compared with the emissions from the distillate oil-fired auxiliary (ICI) boiler.

[see pdf for table]

The proposed rule would impose the following requirements upon an Aux Boiler that has operated an average of 131 hrs per year (from 2005 to 2009):

* Install operate and maintain CO and oxygen CEMS and data acquisition and handling systems.
* Comply with a CO standard on a 30-day rolling average basis.
* Test annually for PM and dioxin/furan, and potentially test annually for HCl and mercury if compliance cannot be demonstrated through fuel-based methods. Assuming compliance can be demonstrated through fuel-based methods, the proposed rule would require at least 15 hours of performance testing per year (three 1-hour PM runs and three 4-hour dioxin/furan runs). If testing for all pollutants is required, the test duration increases to at least 24 hours per year. These times do not include start-up and stabilization. For the subject boiler at Cheswick, operating merely for the purposes of testing results in 10-20% increase in annual operating hours.

Previously, EPA chose to limit emissions from sources operated in non-continuous and infrequent manners by providing a category that restricts operation of these sources to a 10% annual capacity factor. This limited-use subcategory is still necessary and appropriate. In the final rule, EPA must classify ICI boilers by limited or unlimited use and these two subcategories should not be subject to the same requirements. Requiring emissions controls and onerous monitoring for infrequently operated sources is unduly burdensome and doesn't provide a significant contribution to emission reductions sought through this rule.

EPA should establish a Limited Use Category that is exempt from the emissions limits, CEMS, and stack testing requirements. Qualification for the Limited Use Category should be limited to 10% annual capacity factor.

Response: Please refer to the preamble for discussion of the limited use subcategory.

Commenter Name: Stephen R. Gossett
Commenter Affiliation: Eastman Chemical Company
Document Control Number: EPA-HQ-OAR-2002-0058-3137.1
Comment Excerpt Number: 11

Comment: Additional subcategories are needed for new source standards.

The proposed new source standards are unrealistic and, if left unchanged, could seriously endanger the nation's long-term prospects for growth in the manufacturing sector. Reports we hear from suppliers of boilers and air pollution control systems are that they will not be able to supply commercial guarantees to meet the proposed standards. Additional subcategories which focus on the regional fuel supplies (Powder River Basin, Illinois Basin, Central Appalachian, etc) are needed to allow future boilers to be installed across the nation. For example, the top performer used to set the HCl standard for new coal-fired boilers is a boiler which burn sub-bituminous coal, which inherently has much lower chlorine content than eastern coals. A facility on the east coast should not have to meet standards that can be met only by burning a fuel only obtained from hundreds if not thousands of miles away.

Response: See response to comment EPA-HQ-OAR-2002-0058-2960.1, excerpt 61 for additional subcategory based on regional fuel availability or geographic location.

Commenter Name: Tim Keneally
Commenter Affiliation: KapStone Paper and Packaging Corporation
Document Control Number: EPA-HQ-OAR-2002-0058-2673.1
Comment Excerpt Number: 11

Comment: An additional subcategory that EPA needs to establish is one for "limited use" units. Because limited use boilers do not operate on a regular schedule and typically operate for only short periods of time, emissions profiles for these boilers can vary significantly from those of a similar boiler operating in a steady state. A capacity utilization factor of 10% was chosen for the previous boiler MACT final rule as the best means of defining a limited use unit. This definition is equally appropriate for the current rule. Also, given the limited and sporadic operation of emergency and auxiliary boilers, as well as the technical infeasibility of imposing emission limitations on these units, the limited use subcategory should require work practices in lieu of emission limits.

Response: Please refer to the preamble for discussion of the limited use subcategory.

Commenter Name: Britt S. Fleming
Commenter Affiliation: Auto Group
Document Control Number: EPA-HQ-OAR-2002-0058-2775.1
Comment Excerpt Number: 14

Comment: Additionally, EPA's approach to subcategorizing the boilers and process heaters in the Gas 1 subcategory for purposes of establishing the potential floors in the preamble fails to account for units designed and operated to minimize emissions of oxides of nitrogen (NOx) to comply with state and federal permit limits. Units operated to keep NOx levels low will have higher emissions of CO. Thus, CO emissions from these units will be higher than boilers not designed or operated to keep their NOx emissions low and in compliance with permit limits. The CO floor level in the preamble for Gas 1 units ignores these design issues and any emission limits based on the potential CO floor level in the preamble would be difficult, if not near impossible, for these boilers to achieve while also meeting the required NOx permit limits. EPA has discretion to account for design characteristics when setting floors and has failed to do so.

Response: See response to comment EPA-HQ-OAR-2002-0059-2702.1, excerpt 68 for additional subcategory to distinguish between units with low NOx burners.

Commenter Name: Arthur N. Marin
Commenter Affiliation: NESCAUM
Document Control Number: EPA-HQ-OAR-2002-0058-2893.1
Comment Excerpt Number: 14

Comment: Additional sub-categorization for boilers between 10 and 30 mmBtu/hr may also be warranted.

Response: See response to comment EPA-HQ-OAR-2002-0058-2818.1, excerpt 18 for subcategorizing according to heat input size.

Commenter Name: Arthur N. Marin
Commenter Affiliation: NESCAUM
Document Control Number: EPA-HQ-OAR-2002-0058-2893.1
Comment Excerpt Number: 16

Comment: NESCAUM also recommends that EPA create a "limited use" boiler category, which should include units used for less than 200 hours per year or a boiler that comprises less than 10% of annual use with caveats to ensure that facilities do not aggregate many small boilers to avoid compliance with emission limits. These boilers may represent back-up or start-up boilers and should be exempted only if they use 15 ppm ultra-low sulfur content oil.

Response: Please refer to the preamble for discussion of the limited use subcategory.

Commenter Name: Jack Carter
Commenter Affiliation: Weyerhaeuser Company
Document Control Number: EPA-HQ-OAR-2002-0058-2797.1
Comment Excerpt Number: 17

Comment: In the original Boiler MACT, EPA included a limited use subcategory with less stringent emissions limits fitting the non-routine use of these combustion units, their low annual emissions and the resource thriftiness of the regulation as the cost of rarely used controls was avoided. The primary criterion to qualify for this limited use subcategory was having a federally enforceable annual average capacity factor of equal to or less than 10 percent (63.757 in 69 FR 55218).

EPA’s proposed Boiler MACT does not address limited use boilers, although at 63.7491(i) EPA would exempt “temporary” boilers that meet certain criteria including burning gas or liquid fuel, being mobile and being located on site for no more than 180 consecutive days. However, we operate a small number of boilers including gas and solid fuel-fired boilers that are run intermittently that would not qualify as temporary boilers; but these stationary units are operated infrequently or for short periods of time, and are maintained for service as emergency, back-up or replacement during maintenance outages of the primary boiler(s) or for winter supplemental heat supplies as needed. We believe EPA should develop a subcategory for these types of boilers and establish work practices to regulate their emissions instead of applying emission limits developed for or similar to those for boilers running continuously. The annual emissions of these units are low and installing and operating additional controls will not be feasible for this class of boilers. The MACT floor for these limited use boilers should be maintenance work practices because emission limitations are infeasible. We refer EPA to the extensive AWC and AF&PA technical discussions describing these types of units and their emission profiles and the legal and policy rationales for subcategorizing and managing the emissions of this class of boiler using work practices.

Response: Please refer to the preamble for discussion of the limited use subcategory.

Commenter Name: G. Vinson Hellwig and Robert H. Colby
Commenter Affiliation: National Assocation of Clean Air Agencies
Document Control Number: EPA-HQ-OAR-2002-0058-2841.1
Comment Excerpt Number: 23

Comment: NACAA supports the development of subcategories in MACT rule development, where such subcategories are based on meaningful differences in anticipated fuels and unit designs. Because NACAA's technical team identified significant differences in the anticipated emission profiles of wood-fired and coal-fired units, the NACAA Model Permit Guidance separated EPA's solid-fuel category into two subcategories, but, seeing no clear technical difference supporting EPA's limited use subcategory, deleted it.
In the vacated ICI Boiler MACT rule, EPA had established four categories – solid-fuel, liquid-fuel, gas-fuel and limited-use boilers. In the 2000 CISWI rule there was but one category – incinerators. The proposed ICI Boiler MACT rule has 11 subcategories while the proposed CISWI rule would have five subcategories. In support of the explosion in the number of subcategories EPA explains the differences in design between, for example, a coal-fired stoker boiler and a coal-fired PC boiler. However, large boilers do not come off an assembly line[56 Even mass-produced automobiles will exhibit design differences within and between models and manufacturers.] and last for up to 50 years. Almost every large boiler will have differences in design from every other large boiler. Even smaller boilers will have differences in design from small boilers produced by other manufacturers. Accordingly, it is insufficient to simply identify design differences. Where EPA seeks to establish additional subcategories it must explain why those differences matter and point to information in the record that supports its conclusion. In particular, we note that EPA's Boiler MACT categories are based on the nature of the fuel that is consumed while the proposed CISWI rule categories are based on the purpose of the combustion, not the fuel. EPA should identify a consistent rationale for establishing new subcategories.

Response: See preamble for discussion of new subcategories added since proposal and new justification in support of a limited use subcategory. The universe of affected boilers and process heaters is much larger and more diverse than the affected units under the CISWI rulemaking. EPA has the authority to determine the appropriate subcategories for each source category under Section 112 and the basis of subcategorization between multiple source categories do not need to be consistent. The Agency individually examines the available data and characteristics of each source category.

Commenter Name: Stephen R. Gossett
Commenter Affiliation: Eastman Chemical Company
Document Control Number: EPA-HQ-OAR-2002-0058-3137.1
Comment Excerpt Number: 39

Comment: EPA's proposed CO standards for the Gas 2 subcategory and liquid fired boilers are not appropriate for limited use boilers.

Although variability impacts concern all boilers, certain types of boilers are affected more than others. These include limited use boilers such as boilers serving solely or primarily to provide heat during startups, boilers used to supply intermittent steam needs such as a boiler that is idle or shutdown except for periods when the facility is operating at peak loads, and boilers which are serving in a reserve capacity in which they are operating at minimal operating rates except in extraordinary circumstances. For example, a boiler which is used solely during facility startups could spend a large minority of operating time under cold startup conditions or highly variable load conditions. To illustrate, if a boiler is used solely for a startup use, then it may only be fired for 1 to 2 days. Load is dependent totally on the need of the facility and could (and probably will) vary from minimal firing to maximum firing over very short periods. As a result, regardless of the averaging period, the unit could never meet any of the CO limitations for any large boiler subcategory defined under this MACT since the unit will operate at a significant period with elevated CO concentrations.

Response: Please refer to the preamble for discussion of the limited use subcategory.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 161

Comment: One additional subcategory that EPA needs to establish is one for "limited use" units. While the prior Boiler MACT rule treated units with average capacity factors of 10% or less separately, the proposed rule does not continue that approach. Instead, it presumes that limited use units are just like those operated full-time which burn a similar fuel. Limited use sources are like temporary boilers (which are exempt from the rule) in that they operate intermittently and for shorter periods of time (e.g., small package boilers that are only used during mill outages, a backup boiler that runs when other units are being fixed, or a peaking unit used to supplement electric generation during particularly hot summer days). Compared to most boilers, these units spend a far greater percentage of their time starting up and shutting down. (The impact of meeting the proposed limits during periods of startup and shutdown are discussed in greater detail in section XVIII of these comments.) As a result, their emissions profiles differ from sources which operate in efficient steady-state manners. For example, they are likely to experience higher CO levels as the boiler heats up due to incomplete combustion. Similarly, many pollution control technologies are either difficult to use or ineffective during startup and shutdown periods and would be cost prohibitive to install and use for only short periods of time during a year. These are just the sort of "class" and "type" distinctions which merit consideration for subcategorization under §112(d)(2).
Because limited use boilers do not operate on a regular schedule and typically operate for only short periods of time, emissions profiles for these boilers can vary significantly from those of a similar boiler operating in a steady state. 75 FR 32023 ("Combustion units operate most efficiently when operated at or near their design capacity. The combustion efficiency tends to decrease as the unit's load (steam production) decreases."). Given their short run times, there are also technological limitations on how effectively emissions from these units can be controlled, particularly for organic HAP emissions. See Response to Public Comments on Proposed Industrial, Commercial, and Institutional Boilers and Process Heaters NESHAP at 67 (February 25, 2004) ("[W]e could not identify any control technologies that would reduce organic HAP emissions [for limited use boilers]. Therefore, while larger units may emit more than smaller units, we have not identified any appropriate technology or method that could be used to reduce organic HAP emissions."). Finally, since "limited use boilers, when called upon to operate, must

respond without failure and without lengthy periods of startup," National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters; Final Rule, 69 FR 55218, 55232 (September 13, 2004).a significantly larger percentage of their annual operation will be devoted to maintenance and readiness testing than other commercial, industrial, or institutional boilers. These differences justify the creation of a subcategory for limited use boilers and process heaters.

Response: Please refer to the preamble for discussion of the limited use subcategory.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 162

Comment: In March of this year, EPA provided a similar subcategory in its final rule promulgating national emission standards for existing compression-ignition reciprocating internal combustion engines ("CI RICE") with a site rating of less than or equal to 500 brake horsepower. See National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines, 75 FR 9648 (March 3, 2010).
In that Rule, EPA recognized that stationary existing CI RICE should be divided into non-emergency and emergency categories "in order to capture the unique differences between these types of engines." Id. at 9650. Like the limited use boilers described in EPA's September 13, 2004 rule, EPA recognized that these emergency CI RICE are required to operate infrequently and for relatively short periods of time and must be kept in working order during prolonged periods of time when they are not operating.
EPA cited as justification for its emergency unit subcategorization an earlier memorandum titled Subcategorization and MACT Floor Determination for Stationary Reciprocating Internal Combustion Engines ?500 HP at Major Sources, Docket No. EPA-HQ-OAR-2008-0708-0006 (January 21, 2009). See National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines, 74 FR 9698, 9705 (March 5, 2009). This memorandum, in turn, incorporated by reference the rationale found in the memorandum Subcategorization of Stationary Reciprocating Internal Combustion Engines ?500 HP, Docket No. EPA-HQ-OAR-2005-0030-0012 (May 15, 2006), which enumerated four reasons for creating a subcategory for emergency CI RICE:
1. Emergency use units are used when electric power from the local utility is interrupted or becomes unreliable. The duration of the power outages is entirely beyond the control of the source, and, when they do occur (except in the case of a major catastrophe) they rarely last more than a few hours, often only a few minutes.
2. Emissions from these units are expected to be low on an annual basis; emissions occur only during emergency situations or for a very short time to perform maintenance checks and operator training. State and local regulators generally have not required emission controls for emergency power/limited use units.
3. Add-on catalytic control devices that are most applicable to reduce HAP from stationary RICE would be less effective on an annual basis for emergency use units, since emergency use units

generally operate for brief periods. Therefore, a greater percentage of the emergency use units' operation, as compared to operation of peaking or baseload engines, will occur during catalyst warm-up, when the catalyst's effectiveness will be lower.
4. Emergency use units operate for very few hours per year. A survey conducted by the California Air Resources Board indicated that emergency engines are operated about 30 hours per year. Also, the National Fire Protection Association requires 30 minutes per week (27 hours per year) to maintain and test emergency engines. The recently finalized Airborne Toxic Control Measure in California allows districts to approve up to 100 hours per year for maintenance and testing of emergency engines.
Id. at 5-6. While these criteria focus on an "emergency use" subcategory, it is important to note that the limited duration of the use, not the purpose for using the RICE is the key issue. For example, the same rule also creates a subcategory for "black start" engines (engines used to start a turbine generator), which operate during both "emergency and high demand days." National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters; Final Rule, 69 FR 55218 at 9662.

These same criteria justify the establishment of a limited use boiler MACT subcategory. First, limited use boilers are put into service only during maintenance outages, unexpected failures of the main boiler, or "when electric power from the local utility is interrupted or becomes unreliable" and some of these events are "entirely beyond the control of the source." Id. at 5. Second, because of their limited use during the year, "[e]missions from these units are expected to be low on an annual basis." Id. Third, for this same reason, a greater percentage of a limited use boiler or process heater's annual operations will be during startup and shutdown, when emissions controls are less effective. See National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters, 75 FR at 32023. Finally, like emergency CI RICE, limited use boilers operate for only a small portion of the year, typically "10 percent of the year or less." National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters; Final Rule, 69 FR at 55232.
Like emergency and black start CI RICE, limited use units should be placed into a subcategory that recognizes the unique challenges that would be faced monitoring and controlling emissions from these units.

Response: Please refer to the preamble for discussion of the limited use subcategory.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 163

Comment: The unique operating characteristics of limited use boilers, there are practical reasons for creating a limited use subcategory. As noted by Judge Williams in Sierra Club v. EPA, "Section 112(d)(1) authorizes the Administrator to 'distinguish among classes, types, and sizes of sources within a category or subcategory' . . . . [O]ne legitimate basis for creating additional subcategories must be the interest of keeping the relation between ‘achieved’ and ‘achievable’ in accord with common sense and the reasonable meaning of the statute. Sierra Club v. EPA, 479 F.3d 875, 884-85 (D.C. Cir. 2007) (Williams, J., concurring).

Without subcategorization for limited use boilers, these infrequently operated units will need to comply with the same emission limits set by units that operate on a continuous basis. As noted above, “combustion units operate most efficiently when operated at or near their design capacity. The combustion efficiency tends to decrease as the unit’s load (steam production) decreases.” National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters, 75 FR at 32023. Limited use boilers will therefore be operating for a significantly greater percentage of their time during periods of inefficient operation.

While EPA has already attempted to address this problem through the current MACT floor analysis by addressing the reduced efficiency of load-following units through allowances for variability, (See MACT Floor Analysis (2010) for the Industrial, Commercial, and Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants – Major Source at 9-10 (April 2010)) this problem is further amplified for limited use boilers, which EPA did not address in its MACT floor analysis, due to EPA’s decision to include periods of startup and shutdown in determining compliance with MACT. As found by EPA, this was justified because “the standards that we are proposing are daily or monthly averages. Continuous emission monitoring data obtained from best performing units, and used in establishing the standards, include periods of startup and shutdown. Boilers, especially solid fuel-fired boilers, do not normally startup and shutdown more the [sic] once per day. Thus, we are not establishing a separate emission standard for these periods because startup and shutdown are part of their routine operations and, therefore, are already addressed by the standards.” Id. at 32013. Continuous emission monitoring data is not available for all pollutants in the database. To the extent that emission limits are based on stack test data that does not consider SSM events, emission information based on an operator’s knowledge and engineering calculations can be used to incorporate SSM variability into the MACT Floor analysis. Moreover, EPA found that “[p]eriods of startup, normal operations, and shutdown are all predictable and routine aspects of a source’s operation.” Id. Neither of these findings reasonably applies to limited use boilers. First, as discussed above, these boilers cannot practically make measurements over a monthly average given their limited utilization. Second, emergency and backup uses are by definition neither predictable nor routine.

By their very nature, limited use boilers must spend a larger percentage of time in startup, shutdown, or other reduced-efficiency operating conditions than either base-loaded or load-following units. EPA should not require limited use boilers to comply with standards set by the best operated of these more efficient units.

Response: Please refer to the preamble for discussion of the limited use subcategory.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 164

Comment: A capacity utilization factor of 10% was chosen for the previous boiler MACT final rule as the best means of defining a limited use unit. See National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters; Final Rule, 69 FR at 55223. This definition is equally appropriate for the current rule.

Response: Please refer to the preamble for discussion of the limited use subcategory.

Commenter Name: G. Vinson Hellwig and Robert H. Colby
Commenter Affiliation: National Assocation of Clean Air Agencies
Document Control Number: EPA-HQ-OAR-2002-0058-2841.1
Comment Excerpt Number: 25

Comment: EPA proposes to establish four subcategories of wood-fired boilers[57 NACAA has raised a concern that differences in the combustion properties of "wet" wood and dry wood might warrant development of a separate subcategory.] – stoker, fluidized bed, suspension and "fuel cell" – as well as separate subcategories for natural gas and other process gases. Again, EPA provides no demonstration that such subcategories are warranted.

Response: See final rule and preamble for discussion of how units are assigned to subcategories and provisions available to switch subcategories.

Commenter Name: N/A
Commenter Affiliation: Sierra Club, Clean Air Task Force, Earthjustice, and Natural Resources Defense Council
Document Control Number: EPA-HQ-OAR-2002-0058-3187.1
Comment Excerpt Number: 4

Comment: EPA also describes a subcategory of small boilers of all kinds. That subcategory, for sources burning any fuel at a rate less than 10 MMBtu per hour, while purportedly based on "size" of source, is justified by the Agency only on assertions that "the standard reference methods for measuring emissions of mercury, CO..., D/F, HCl ... and PM...are generally not able to accurately sample small diameter (less than 12 inches) stacks. ... Units that have capacity below 10 million MMBtu per hour generally have [such small diameter] stacks...[a]lso, many existing small units do not currently have sampling ports and a platform." 75 Fed. Reg. 32,024. In fact, this distinction is really one of costs – EPA further asserts that the costs to demonstrate compliance with technology based limits at these units "would have a significant adverse effect on these facilities" which EPA says would vary by facility size (i.e., smaller facilities would be less likely to be able to bear the costs). Id.

Response: See response to comment EPA-HQ-OAR-2002-0058-2818.1, excerpt 18 for subcategorizing according to heat input size.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 143

Comment: EPA has developed subcategories of boilers under the proposed rule by fuel type, and in some cases, boiler type. We believe that it is appropriate to develop subcategories based on these criteria, as it recognizes the differences in boiler design, operation, and emissions. For example, a solid-fired unit having the combustion occur on a grate has different challenges for optimizing the fuel-air ratio than that of a unit in which the combustion occurs in suspension. Combustion on a grate is subject to piling and smoldering that cannot simply be controlled by increasing the amount of excess air, yet can cause CO emissions to spike unexpectedly.

Response: See response to comment EPA-HQ-OAR-2002-0058-3213.1, excerpt 148 for further subcategorization by fuel type.
See response to comments EPA-HQ-OAR-2002-0058-2916, excerpt 2 and EPA-HQ-OAR-2002-0058-2702.1, excerpt 54 for subcategories for based on design type, and for cyclone, firetube, and hybrid watertube-firetube boilers.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 145

Comment: EPA has broad discretion to establish subcategories of sources. Section 112 provides EPA with explicit authority "to establish subcategories under this section, as appropriate." § 112 (c)(1); see also §112 (c)(5) ("… the Administrator may at any time list additional categories and subcategories of sources[.]"). Indeed, § 112 establishes a presumption in favor of the creation and modification of categories and subcategories in the course of the Agency's regulatory program, by mandating that EPA "shall from time to time, but no less often than every 8 years, revise, if appropriate, in response to public comment or new information, a list of all categories and subcategories of major sources[.]" §112(c)(1).
Section 112(c)(1)'s language empowering EPA "to establish subcategories … as appropriate" without the inclusion of criteria limiting the Agency's ability to do so confers a broad grant of authority. The D.C. Circuit previously has interpreted the inclusion of the phrase "as appropriate" in a more limiting statutory mandate as conferring substantial discretion. Consumer Federation of America v. U.S. Dept. of Health and Human Services, 83 F.3d 1497 (D.C. Cir. 1996).
At issue was a provision of the Clinical Laboratory Improvement Amendments of 1988, which directed HHS to establish qualifications for laboratory technicians that "shall, as appropriate, be

different on the basis of the type of examinations and processes being performed[.]" Id. at 1503. The court found that, even though the statutory mandate at issue – using the word "shall" – was phrased in a way generally interpreted to impose a mandatory duty to differentiate qualifications based on different types of tests, the inclusion of the words "as appropriate" removed the mandatory nature of this provision and introduced a significant amount of agency discretion in its implementation. Id. To hold otherwise, concluded the court, would treat the statutory terms "as appropriate" as mere surplussage, thereby violating a basic canon of statutory construction. Id. In the CAA context, the mandate conferred by §112 to establish subcategories "as appropriate" similarly provides substantial discretion for EPA to create subcategories on any reasonable basis. Nothing in the Act or applicable caselaw suggests otherwise.

While EPA has nearly unfettered discretion to create subcategories as appropriate, the CAA provides ample authority for EPA to distinguish among groups of sources within a source category or subcategory in setting a MACT standard. The statute provides that EPA "may distinguish among classes, types and sizes of sources within a category or subcategory" when establishing MACT standards. 42 U.S.C. § 7412(d)(1) (emphasis added). Congress' use of the broad terms "class," "type," and "size" shows that EPA is intended to have broad discretion in the appropriate factors that warrant distinguishing among sources, and EPA's proposed subcategories fall squarely within the meaning of "types" and "sizes."

It is a well-established canon of statutory construction that courts "give the words of a statute their ordinary, contemporary, common meaning, absent an indication Congress intended them to bear some different import." Williams v. Taylor, 529 U.S. 420, 431, 120 S.Ct. 1479, 1487-88, 146 L.Ed.2d 435 (2000). Accordingly, we turn to the standard definitions of "class," "type" and "size." Webster's Third New International Dictionary Unabridged (1993) defines "class" to mean "a group, set or kind marked by common attributes or a common attribute." It defines "type" as "qualities common to a number of individuals that serve to distinguish them as an identifiable class or kind," further clarifying that "'[t]ype', 'kind' and 'sort' are usually interchangeable" and that "'kind' in most uses is likely to be very indefinite and involve any criterion of classification whatsoever." To the extent that EPA may distinguish among sources within a category or subcategory on the basis of "any [reasonable] criterion of classification whatsoever," and may create subcategories as appropriate, the CAA strongly supports EPA's authority to create subcategories of industrial boilers as proposed.

Response: The EPA thanks the commenters for their support and recognonition of EPA's authority to create subcategories based on legislative history, case law and the CAA.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 146

Comment: The legislative history makes clear that Congress intended EPA to distinguish among classes, types and sizes of sources under three core circumstances: when differences among sources affect (1) the feasibility of air pollution control technology; (2) the effectiveness of air pollution control technology; and (3) the cost of control.

The Senate Report clarifies that the Administrator should:
“take into account factors such as industrial or commercial category, facility size, type of process and other characteristics of sources which are likely to affect the feasibility and effectiveness of air pollution control technology. Cost and feasibility are factors which may be considered by the Administrator when establishing an emission limitation for a category under section 112. The proper definition of categories, in light of available pollution control technologies, will assure maximum protection of public health and the environment while minimizing costs imposed on the regulated community. However, in limited circumstances where a group of sources may share the characteristics of other sources in the category, the Administrator may establish subcategories for such sources.” S. Rep. No. 228, 101st Cong., 1st Sess 166.
Thus, in the view of the Senate, the standard for establishing categories and subcategories is essentially the same, although the Administrator is cautioned not to make too rampant use of subcategories.
The House Report similarly provides: “EPA may distinguish among classes, types and sizes of sources within a category or subcategory. . . . 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 measures, or to drive sources to the brink of shutdown.” House Rep. No. 101-490, Part 1, at 328.
In sum, while Congress intended the MACT program to achieve significant emissions reductions, it also intended EPA to be cognizant of the costs of control, and to ensure that the program did not cause significant economic hardship. One primary mechanism for achieving this goal is through the use of subcategories; subcategorization enables the Agency to account for the fact that distinctions among classes, types and sizes of sources may have a very real impact on the feasibility of a given control technology, the effectiveness of that control technology, and the cost of control.

Response: See response to comment EPA-HQ-OAR-2002-0058-3213.1, excerpt 145 for EPA’s authority to create subcategories.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 147

Comment: The only case to interpret the “classes, types and sizes” language supports this interpretation. Sierra Club v. Costle, 657 F.2d 298 (D.C. Cir. 1981), recognized the broad discretion this language confers on EPA to create what in effect are subcategories of sources with differentiated emission standards. This decision interpreted identical statutory language found in the New Source Performance Standards (NSPS) provisions of § 111 of the CAA. Under the “classes, types and sizes” language, the Sierra Club court upheld a variable NSPS SO2 reduction requirement that was tied to a source’s existing SO2 emissions levels which, in turn, depended on the sulfur content of the facility’s fuel. The Court noted that “[t]he required finding

that must underlie a variable standard is much broader than a mere determination that uniformity is not achievable. Rather, EPA has the discretion to vary the standard upon finding that such a departure (from uniform control) does not undermine the basic purposes of the Act." Id. at 321. On this basis, the Court expressly upheld EPA's subcategorization of coal-fired power plants based on the sulfur content of fuel, finding that "[c]ertainly the text of the statute nowhere forbids a distinction based on sulfur." See id. at 319. More generally, the Sierra Club decision confirms EPA's discretion to set differentiated emissions standards for groups of sources within a category – i.e, for subcategories – even in instances where the strictest standard may be achievable by all sources.
The Report further provides that "Nothing in this language authorizes the establishment of a category based wholly on economic grounds, nor is there any implication that individual facilities may be granted categorical waivers … based on assertions of extraordinary economic effect." Id. In other words, the cost of control is an appropriate basis for distinguishing among sources so long as it is not the only basis that distinguishes among those sources.
The Court's analysis in Sierra Club has obvious relevance to an analysis of the authority granted to EPA through CAA § 112. Section 112 employs the same language as Section 111 in defining when EPA may promulgate distinct emission standards for sources within a category or subcategory. The Supreme Court consistently has held that "when administrative and judicial interpretations have settled the meaning of an existing statutory provision, repetition of the same language in a new statute indicates, as a general matter, the intent to incorporate its administrative and judicial interpretations as well." Bragdon v. Abbott, 524 U.S. 634, 645 (1998). Therefore, § 112, which adopted § 111's terms almost ten years after the D.C. Circuit issued the Sierra Club decision, must be understood to carry the settled meaning given to those terms by Sierra Club.

Response: See response to comment EPA-HQ-OAR-2002-0058-2960.1, excerpt 61 for additional subcategory based on regional fuel availability or geographic location.
See response to comment EPA-HQ-OAR-2002-0058-3213.1, excerpt 145 for EPA's authority to create subcategories.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 148

Comment: EPA's past practice has been consistent with this interpretation of the Act. The Agency has subcategorized sources in numerous industrial categories. From this experience, it is possible to distill several principles that have guided the Agency's decision making with regard to creation of subcategories. First, EPA has determined that subcategorization is appropriate where sources use different processes, and those processes result in different types or concentrations of uncontrolled HAPs. Here, for example, the suite of HAPs emitted by solid-fueled boilers differs from that emitted by liquid-fueled boilers, which in turn differs from that emitted by gas-fueled boilers. For example, the types of metals emitted by solid-fueled boilers differs from the types of metals emitted by liquid-fueled boilers– and gas-fueled boilers typically emit little metals, but may emit more organic HAPs. See 68 Fed. Reg. at 1670. Thus, subcategorization based on fuel type is appropriate because the different types of boilers emit different types of HAPs.

Response: The EPA disagrees with commenter's suggestion to further subcategorize by fuel type. Although the EPA recognizes the variation in emissions between different fuel types, many units burn a mixture of fuel types and EPA determined that its combustor design-based classifications for organic HAP pollutants appropriately distinguish between operating and design characteristics of boilers that burn a single fuel type. The EPA also considers that variability has been incorporated into the MACT floor analysis because the emission limits developed for the MACT floor level of control incorporate boilers using various fuels and variations of control devices.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 149

Comment: The Agency has subcategorized sources based on size, where size differences affect the performance of control technologies, such as where more frequent start up and shut down makes it more difficult for smaller sources to maintain the same level of control as larger sources. That is also the case here. There are fundamental differences in the design of small boilers, as compared to large boilers. Moreover, smaller units often are used in swing load mode, whereas larger units more typically are base-loaded. These smaller boilers have more frequent start ups and shut downs that impact the performance of control technology, and hence the achievability of the standard. Thus, subcategorization of boilers based on size – or infrequent utilization – also is consistent with EPA's past precedent and is appropriate because of the impact of these factors on the ability of these sources to maintain the same level of control as larger sources.

Response: See response to comment EPA-HQ-OAR-2002-0058-2818.1, excerpt 18 for subcategorizing according to heat input size.

Please refer to the preamble for discussion of the limited use subcategory.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 150

Comment: Furthermore, the Agency has subcategorized sources where differences among sources affect the applicability of control technology. For example, EPA created subcategories in the 1999 polyether polyols production MACT standard, finding that "[s]ubcategorization was necessary due to the distinctively different nature of the epoxide and THF processes and its effect on the applicability of controls." Similarly, in the 1998 flexible polyurethane foam production MACT standard, EPA found that "[s]ubcategorization was necessary to reflect major variations in production methods, and/or HAP emissions that affect the applicability of controls." Based on similar rationales, EPA created subcategories in the Group I polymers and resins MACT and the primary aluminum production MACT, and proposed to create subcategories in the polyurethane foam production MACT. Here, for example, fabric filters may be an appropriate control technology to capture metals from coal-fired boilers, but are not appropriate for use on oil-fired boilers because the soot blinds the bags of the fabric filter, and is also a fire hazard. Thus, subcategorization based on fuel type is appropriate because the type of fuel affects the applicability of control technology.

Response: See response to comment EPA-HQ-OAR-2002-0058-3213.1, excerpt 148 for further subcategorization by fuel type.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 61

Comment: Imposing emission limits on liquid-fired boilers and process heaters, versus work practice requirements for most gas-fired boilers and process heaters, will tend to drive sources to replace liquid-fired units with natural gas-fired units. However, some facilities do not have this option. For instance, some facilities in Alaska and those on isolated islands (e.g., Hawaii and the Virgin Islands) have no option to use imported gaseous fuels rather than liquid fuels to meet their fuel balance needs and in most of these cases, even the choice of liquid fuels is quite restricted.

Refineries and crude loading facilities located on islands or remote locations, such as Alaska, have unique configurations and constraints that mainland refineries and loading facilities do not. One of the key constraints is that islands and remote locations cannot physically access natural gas pipelines. This makes the burning of liquid fuels (produced on site or purchased locally) an unavoidable part of doing business in those locations, as EPA observes in the rule preamble. Moreover, the dual fired heaters used at many island/remote facilities are a very different design than EPA apparently contemplated in establishing subcategories and this design also affects the combustion chamber design.

In these situations, facilities are also limited in what liquid fuels they can use. They may have only one practical supplier of fuel oil. For refineries that is typically the refinery itself. The HAP metals and chlorine content of those liquid fuels is set by the refinery crude slate and process. These facilities do not have an option to seek out lower metal or chloride fuels and must use what is produced or available locally. In his concurring opinion in the Brick MACT case, Judge Williams stated that EPA's ability to create subcategories for sources of different classes, size, or type (CAA section 112(d)(1)) may provide a means out of the situation where the floor standards are achieved for some sources, but the same floors cannot be achieved for other sources due to differences in local raw materials whose use is essential. Such an approach would allow EPA to address the special problems of facilities in remote locations where access to natural gas and alternate liquid fuels is non-existent or extremely limited.

Because of their very different properties, fuel oils cannot be combusted in the same burner elements as gas fuels. They can be simultaneously combusted in a burner equipped with both oil and gas burner elements, which changes combustion dynamics and is an operating mode not apparently recognized by EPA in the development of this proposal.

At refineries without natural gas supplies, fuel gas produced by units like Fluid Catalytic Cracking units and Delayed Coking units can constitute up to 60% of the total refinery fuel gas production. When those units experience upsets or planned or unplanned shutdowns or slowdowns, fuel oil usage will increase to balance the energy supply. Slowdowns can occur for a variety of reasons, such as unfavorable economics, maintenance or fuel quality limitations. Refineries and other facilities typically have planned shutdowns for major maintenance of individual units, which can occur on 3 to 6 year intervals, depending on the unit. Unplanned unit shutdowns occur due to unpredictable unit malfunction. Whether planned or unplanned, shutdowns or slowdowns can greatly affect the amount of fuel gas and fuel oil that must be burned to maintain an energy balance.

In addition to shutdowns and slowdowns, fuel gas producing units can experience daily variations in their gas production by as much as 20% in one hour. One example of this is Delayed Cokers, which are batch processes. Delayed Cokers have cycle times between 12 and 18 hours, and the amount of gas produced varies by time in the cycle. Another example is daily variation in fuel gas production due to ambient temperature differences between night and midday, particularly for warm temperature climates such as the Caribbean or Hawaii.

Other operational factors can also significantly change the amount of fuel gas available. For example, feedstock quality changes or feed rate changes to gas producing units will affect the amount of gas produced. The effect is that the facility must switch from gas to oil, or vice versa, to balance the fuel needs of the facility.

There is a particular problem with meeting CO limits for refineries without natural gas access. A critical factor in low CO operation is a stable, consistent operation that maintains combustion conditions conducive to complete combustion. While refineries are typically dynamic operations and may experience rate turndowns, island and remote location facilities have operational issues relating to fuel oil burning that go well beyond typical refineries. For the reasons discussed above, large daily and episodic variations in fuel gas production, gas composition and heating value, and fuel demand changes results in large variations in fuel oil consumption for each fuel-oil burning unit. These swings are made manually by switching burners and/or burner tips from gas to oil or vice-versa and then manually adjusting excess air. One or more burners can be switched over a period of hours to adjust the fuel balance. Switching burners from oil to gas requires step processing to prevent surging the refinery fuel gas system pressure and releasing fuel gas into the flare system. This is not a precise science and the nature of these manual adjustments makes it difficult to optimize oxygen levels in the heater or boiler around a 3% excess oxygen target during this switching. These changes can also result in flame impingement on the heater tubes or in the boiler firebox. The result will be higher CO and less efficient combustion. EPA failed to take these types of variations into account in setting the MACT floors for liquid burning units. For CO for example, EPA relied on stack test data as opposed to CEM data to come up with a proposed limit. A stack test will not reflect burning condition variations due to fuel swings as facilities that were tested were not in island/remote locations and will hold a unit steady during the test.

Subcategorization has been used to address special situations involving small groups of facilities and that approach could be used here to address this concern. For instance, in the stationary combustion turbine NESHAP, a much more homogeneous source category than boilers and process heaters, eight subcategories were established, including a subcategory to address stationary combustion turbines operated on the North Slope of Alaska (defined as the area north of the Arctic Circle (latitude 66.5° North)). The special situation at remote refineries has also been addressed in the Part 60 rules. For instance, subpart KKKK of part 60 establishes a separate sulfur content limit for distillate used for power generation turbines in Hawaii.

Recommendation: Create a subcategory for boilers and process heaters in locations without access to natural gas and with limited access to alternate liquid fuels and only apply work practice requirements to boilers and process heaters in such locations.

Response: See preamble for discussion of the new non-continental subcategory.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 105

Comment: The data fail to include a representation of the many units that run in standby mode or at significantly turned down rates most of the time. This situation is common for standby and emergency boilers, boilers whose demand varies substantially by season, process heaters where demand varies significantly with changing process operations, and process heaters which have high demand only intermittently. For instance, in some catalyst operations, feed heaters operate at very low rates when the catalyst is fresh, but ramp up to higher rates as the catalyst ages, perhaps over a period of years. Other process heaters may operate at very low rates except during process startups when certain special operations occur (e.g., catalyst regenerations) or for certain process line-ups or production of certain products.

Response: See the preamble for revisions made for limited use boilers.

Commenter Name: William A. Moore
Commenter Affiliation: Luminant
Document Control Number: EPA-HQ-OAR-2002-0058-2780.1
Comment Excerpt Number: 1

Comment: Luminant has 18 distillate oil- and natural gas- fired auxiliary boilers used for startup that will be directly impacted by this rule. These auxiliary boilers have heat input ratings from approximately 20 mmBtu to 480 mmBtu and perform startup steam functions, including providing sealing steam to the primary turbine and boiler feed pump turbine glands which prevent air leakage into, and steam leakage from, the turbine cylinders. Once the main utility boiler can reliably provide this sealing steam,the auxiliary boiler can be removed from service. Therefore, the auxiliary boilers have a very limited use and are in a transitional state of operation most of that operating time.

Response: Please refer to the preamble for discussion of the limited use subcategory.

Commenter Name: Robert Karworski
Commenter Affiliation: Whirlpool Corporation
Document Control Number: EPA-HQ-OAR-2002-0058-2403.1
Comment Excerpt Number: 4

Comment: “Stand-by” Boilers
A Whirlpool facility has a Gas 1 stand-by boiler that is normally used for short periods, once or twice a year. This unit serves as a back-up for the other units. In 2009, the unit had zero hours of operation. Whirlpool requests an exemption to the rule for Gas 1 boilers in this 10 to 100 MMBtu range when used less than 10% of the time in a calendar year. We request that these units be governed under the same rules as the less than 10 MMBtu boilers as long as they qualify as a stand-by unit.

Response: Please refer to the preamble for discussion of the limited use subcategory.

Commenter Name: William A. Moore
Commenter Affiliation: Luminant
Document Control Number: EPA-HQ-OAR-2002-0058-2780.1
Comment Excerpt Number: 4

Comment: Section 112(c) of the CAA authorizes EPA to establish a list of all categories and subcategories of major sources, “as appropriate,” and § 112(d) provides that EPA “may distinguish among classes, types, and sizes of sources within a category or subcategory in establishing” MACT standards. 42 U.S.C. § 7412(c), (d). EPA has exercised this broad authority and has proposed to subcategorize boilers and process heaters by unit design and further by combustion systems. See 75 Fed. Reg. 32,006, 32,017 (June 4, 2010).

Luminant supports EPA's subcategorization based on both unit design and on combustion method. EPA correctly recognizes that "there are significant design and operational differences between units that burn coal, biomass, liquid, and gaseous fuels," and that "[b]oiler systems are designed for specific fuel types and will encounter problems if a fuel with characteristics other than those originally specified is fired." Id. Further, EPA is correct that "because different types of units have different emission characteristics which may influence the feasibility or effectiveness of emission control, they should be regulated separately, (i.e., subcategorized)." Id. EPA's stated reasons for subcategorizing also support development of at least two additional subcategories, as discussed below.

Response: See response to comment EPA-HQ-OAR-2002-0058-3213.1, excerpt 145 for EPA's authority to create subcategories.

Commenter Name: William A. Moore
Commenter Affiliation: Luminant
Document Control Number: EPA-HQ-OAR-2002-0058-2780.1
Comment Excerpt Number: 5

Comment: EPA should include a subcategory for low capacity startup boilers. Luminant has a number of low capacity, auxiliary startup boilers that would be impacted by this proposed rule. For example, Luminant has two distillate-fired boilers that have each averaged approximately 75 annual operating hours for the past 10 years. The proposed subcategories do not account for the unique characteristics of these boilers. Without such a subcategory, the NESHAP would require low-capacity-factor boiler operators to expend inappropriately large amounts of time and expense with an inversely proportional actual reduction in emissions. And, in fact, in some cases, merely completing the required testing would add 20 to 30% to the total emissions for that boiler in a year. That is counterproductive to achieving emissions reductions and, because much of the steam generated during the required testing would be wasted, counter to good energy policies.

EPA has already determined that these auxiliary ("limited use") boilers should have their own subcategory. See 68 Fed. Reg. 1660, 1670 (Jan. 13, 2003) (original proposed rule). Specifically, EPA stated that
[a] review of the information gathered on boilers also shows that a number of units operate as backup, emergency, or peaking units that operate infrequently. Back-up or emergency units only operate if another boiler that is the regular source of energy or steam is not operating (for example due to a shutdown for maintenance or repair). Peaking units operate only during peak energy use periods, typically in the summer months. The boiler database indicates that these infrequently operated units typically operate 10 percent of the year or less. These limited use boilers, when called upon to operate, must respond without failure and without lengthy periods of startup. While these are potential sources of emissions, and it is appropriate for EPA to address them in the proposal, the Agency believes that their use and operation are different compared to typical industrial, commercial, and institutional boilers. Consequently, we decided that such limited use units should have their own subcategory.Id. (emphasis added). Yet, although both the old and new rule recognize the special circumstance of boilers with heat input

capacity of less than 10 mmBtu/hr, the new rule does not similarly recognize the inefficiency of regulating limited-use boilers, which have very small capacity factors. Cf. 69 Fed. Reg. 55,218, 55,268 (Sept. 13, 2004) (defining “limited use” subcategories to include boilers or process heaters with a rated capacity of greater than 10 mmBtu/hr and “a federally enforceable annual average capacity factor of equal to or less than 10 percent.”). EPA should add a subcategory for low capacity startup boilers such as those operated by Luminant.

Response: Please refer to the preamble for discussion of the limited use subcategory.

Commenter Name: Mary Graham
Commenter Affiliation: Charleston Metro Chamber of Commerce
Document Control Number: EPA-HQ-OAR-2002-0058-2732.1
Comment Excerpt Number: 9

Comment: An additional subcategory that EPA needs to establish is one for "limited use" units. Because limited use boilers do not operate on a regular schedule and typically operate for only short periods of time, emissions profiles for these boilers can vary significantly from those of a similar boiler operating in a steady state. A capacity utilization factor of 10% was chosen for the previous boiler MACT final rule as the best means of defining a limited use unit. This definition is equally appropriate for the current rule. Also, given the limited and sporadic operation of emergency and auxiliary boilers, as well as the technical infeasibility of imposing emission limitations on these units, the limited use subcategory should require work practices in lieu of emission limits.

Response: Please refer to the preamble for discussion of the limited use subcategory.

Commenter Name: David A. Buff
Commenter Affiliation: Golder Associates Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2801.1
Comment Excerpt Number: 13

Comment: Limited use units are those units that operate a very limited amount of time on an annual basis, i.e., less than 10 percent or 20 percent of the time annually. The proposed rule does not address limited use units. In essence, an affected source that operated a limited amount of time would have to meet the same limits as a source that operates year-round. EPA addresses the rationale for and development of work practice standards for small boilers and process heaters [<10 million British thermal units per hour (MMBtu/hr) heat input]. EPA cites the technological and economic limitations and impacts of imposing emission limits, stack testing requirements, etc., on these small boilers.

Many of these same arguments are applicable to limited use units. Although some limited use units may be more amenable to stack testing, many of these units are not equipped with stack sampling facilities, and for many it would not be technologically feasible to stack test (i.e., sampling ports would not meet minimum criteria; platforms would not be able to be installed without significant cost, etc.). Also, due to their limited operation (presumably as a backup to another boiler), it would be difficult to schedule a stack test on these units. CO and PM CEMS would be very costly to install for little use or benefit.

The FSI therefore requests that work practice standards be set for limited use units, in the same manner as for small units.

Response: Please refer to the preamble for discussion of the limited use subcategory.

Commenter Name: Donald R. Schregardus
Commenter Affiliation: Department of Defense
Document Control Number: EPA-HQ-OAR-2002-0058-2763.1
Comment Excerpt Number: 15

Comment: It is recommended that EPA reassess the establishment of a CO limit for oil-fired boilers, especially existing boilers, and base the MACT floor on a more representative subset of boilers currently in operation that takes into account the potential background levels of CO in the combustion air.
As proposed, all new oil-fired boilers and all existing oil-fired boilers greater than 10 MMBtu/hr are subject to emission limits. The final rule should differentiate requirements between emergency and nonemergency oil-fired boilers. Emergency boilers, like emergency generators, operate primarily during routine maintenance/testing. In many cases, subjecting emergency boilers to the same testing and monitoring requirements as nonemergency boilers to demonstrate compliance with emission limits would increase their operating time and result in little, if any, air quality benefit.

The hospital at a DoD facility in Alaska has three 19 MMBtu/hr oil-fired boilers that produce steam to heat the facility in the event of a utility outage. Because the military installation is a major source facility, the hospital's emergency boilers are subject to the major source version of the proposed rule. The three oil-fired boilers are permitted (Title V) to operate 600 hours, combined, during any consecutive 12-month period. Each boiler is subject to and complies with New Source Performance Standards, 40 CFR §60, Subpart Dc. The average consecutive 12-month run time during 2010 is 14 hours per boiler (emergency plus maintenance/testing). A conservative estimate for stack testing one boiler is eight hours. The annual stack test alone would increase each boiler's average consecutive 12-month run time from 14 hours to 22 hours. With added monitoring and/or need to retest, it is feasible that the rule would cause each boiler to double its annual run time.

Establish a subcategory for emergency use, oil-fired boilers and establish work practice standards in lieu of application of the currently proposed emission limits for these units. Similar to the alternative requirements for emergency utility equipment within the Stationary Reciprocating Internal Combustion Engine (RICE) NESHAP, enforcing work practice standards for emergency use boilers within the Boiler MACT would promote efficient operating conditions while minimizing the risk of increasing operating time and emissions.

Response: Please refer to the preamble for discussion of the limited use subcategory.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 30

Comment: In this proposal, sources have been subcategorized by fuel fired and, for solid fuels, further subcategorized by equipment design. Subcategorization has been used very sparingly for other purposes (e.g., to distinguish <10 MMBTU/hr boilers and process heaters from >10 MMBTU/hr units). Many special issues that could have been dealt with by subcategorization have, therefore, not been addressed and cause many problems in the proposal. For instance by not subcategorizing boilers and process heaters below 1 or 5 MMBTU/hr as a separate subcategory, the proposal would wastefully and for no benefit make very small units subject to the tune-up requirements. We have tried to point out in our comments situations where further subcategorization would be helpful and we suggest the Agency greatly increase the use of this approach to address those situations (e.g., limited use; turndown, startup and shutdown, faculties with no access to natural gas).

It is worth noting that the Stationary Combustion Turbine MACT has successfully used subcategorization to address special situations. That rule established eight subcategories of turbine (a much more homogeneous source category than boilers and process heaters0 as follows: (1) Emergency stationary combustion turbines, (2) stationary combustion turbines which burn landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis or where gasified MSW is used to generate 10 percent or more of the gross heat input to the stationary combustion turbine on an annual basis, (3) stationary combustion turbines of less than 1 MW rated peak power output, (4) stationary lean premix combustion turbines when firing gas and when firing oil at sites where all turbines fire oil no more than 1000 hours annually (also referred to herein as ??lean premix gas-fired turbines“), (5) stationary lean premix combustion turbines when firing oil at sites where all turbines fire oil more than 1000 hours annually (also referred to herein as ??lean premix oil-fired turbines“), (6) stationary diffusion flame combustion turbines when firing gas and when firing oil at sites where all turbines fire oil no more than 1000 hours annually (also referred to herein as ??diffusion flame gas-fired turbines“), (7) stationary diffusion flame combustion turbines when firing oil at sites where all turbines fire oil more than 1000 hours annually (also referred to herein as ??diffusion flame oilfired turbines“), and (8) stationary combustion turbines operated on the North Slope of Alaska (defined as the area north of the Arctic Circle (latitude 66.5° North)).

Similarly, the Reciprocating Internal Combustion Engine MACT has 9 subcategories, as follows: (1) Stationary RICE with a site-rating of 500 brake HP or less, (2) emergency stationary RICE,

(3) limited use stationary RICE, (4) stationary RICE that combust landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, and (5) other stationary RICE. We further divided the last subcategory into four subcategories: (1) 2SLB stationary RICE, (2) 4SLB stationary RICE, (3) 4SRB stationary RICE, and (4) CI stationary RICE.

Recommendation: Use further subcategorization to address special situations, such as limited use boilers and process heaters; turndown, startup and shutdown operations, and boilers and process heaters located at facilities without access to natural gas.

Response: Please refer to the preamble for discussion of the limited use subcategory.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-2702.1
Comment Excerpt Number: 46

Comment: CIBO Strongly Supports EPA’s Proposal to Create Subcategories of lndustrial Boilers and Process Heaters.
CIBO strongly supports EPA’s proposal to subcategorize industrial boilers and process heaters based on the physical state of the fuel burned. CIBO agrees with EPA’s conclusion that "there are significant design and operational differences between units that burn coal, biomass, liquid, and gaseous fuels" and that "[b]oiler systems are designed for specific fuel types and will encounter problems if a fuel with characteristics other than those originally specified is fired." 75 FR 32017. These subcategories therefore reflect significant technological differences with corresponding differences in the nature, composition, and controllability of HAP emissions, as well as the cost of control. CIBO similarly supports EPA’s ability to subcategorize further among units firing fuel of the same physical state based on size and extent of use. The design and construction of large and small units reflect further technological differences that affect the nature, composition, and controllability of HAP emissions.

Response: See response to comment EPA-HQ-OAR-2002-0058-2818.1, excerpt 18 for subcategorizing according to heat input size.
See response to comment EPA-HQ-OAR-2002-0058-3213.1, excerpt 145 for EPA’s authority to create subcategories.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-2702.1
Comment Excerpt Number: 48

Comment: EPA has Abundant Legal Authority to Create Subcategories as Proposed.

EPA has broad discretion to establish subcategories of sources. Section 112 provides EPA with explicit authority "to establish subcategories under this section, as appropriate." § 112(c)(I); see also § 112(c)(5) (" ...the Administrator may at any time list additional categories and subcategories of sources[.],,). Indeed, § 112 establishes a presumption in favor of the creation and modification of categories and subcategories in the course of the Agency's regulatory program, by mandating that EPA "shall from time to time, but no less often than every 8 years, revise, if appropriate, in response to public comment or new information, a list of all categories and subcategories of major sources." § 112(c)(I). Section 112(c)(I)'s language empowering EPA "to establish subcategories ... as appropriate" without the inclusion of criteria limiting the Agency's ability to do so confers a broad grant of authority.

The D.C. Circuit previously has interpreted the inclusion of the phrase "as appropriate" in a more limiting statutory mandate as conferring substantial discretion. Consumer Federation of America v. U.S. Dept. of Health and Human Services, 83 F.3d 1497 (D.C. Cir. 1996) (Consumer Federation). At issue in Consumer Federation was a provision of the Clinical Laboratory Improvement Amendments of 1988 (CLIA), which directed HHS to establish qualifications for laboratory technicians that "shall, as appropriate, be different on the basis of the type of examinations and processes being performed." Consumer Federation, 83 F.3d at 1503.

The court found that, even though the statutory mandate at issue-using the word "shall"-was phrased in a way generally interpreted to impose a mandatory duty to differentiate qualifications based on different types of tests, the inclusion of the words "as appropriate" removed the mandatory nature of this provision and introduced a significant amount of agency discretion in its implementation. Consumer Federation, 83 F.3d 1497. To hold otherwise, concluded the court, would treat the statutory terms "as appropriate" as mere surplussage, thereby violating a basic canon of statutory construction. Consumer Federation, 83 F.3d 1497. In the CAA context, the mandate conferred by § 112 to establish subcategories "as appropriate" similarly provides substantial discretion for EPA to create subcategories on any reasonable basis. Nothing in the Act or applicable case law suggests otherwise.

Response: See response to comment EPA-HQ-OAR-2002-0058-3213.1, excerpt 145 for EPA's authority to create subcategories.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-2702.1
Comment Excerpt Number: 49

Comment: EPA Has Broad Discretion to Distinguish Among Classes, Types and Sizes of Sources, Even Within Subcategories.
While EPA has nearly unfettered discretion to create subcategories as appropriate, the CAA provides ample authority for EPA to distinguish among groups of sources within a source category or subcategory in setting a MACT standard. The statute provides that EPA "may distinguish among classes, types and sizes of sources within a category or subcategory" when

establishing MACT standards. 42 U.S.C. § 7412(d)(I). Congress's use of the broad terms "class," "type," and "size" shows that EPA is intended to have broad discretion in the appropriate factors that warrant distinguishing among sources, and EPA's proposed subcategories fall squarely within the meaning of "types" and "sizes." It is a well-established canon of statutory construction that courts "give the words of a statute their ordinary, contemporary, common meaning, absent an indication Congress intended them to bear some different import." Williams v. Taylor, 529 U.S. 420, 431 (2000) (quotations omitted).

Accordingly, we turn to the standard definitions of "class," "type" and "size." Webster's Third New International Dictionary Unabridged (1993) defines "class" to mean "a group, set or kind marked by common attributes or a common attribute." It defines "type" as "qualities common to a number of individuals that serve to distinguish them as an identifiable class or kind," further clarifying that "[t]ype", "kind" and "sort" are usually "interchangeable and that "kind" in most uses is likely to be very indefinite and involve any criterion of classification whatsoever." To the extent that EPA may distinguish among sources within a category or subcategory on the basis of "any [reasonable] criterion of classification whatsoever," and may create subcategories as appropriate, the CAA strongly supports EPA's authority to create subcategories of industrial boilers as proposed.

Response: See response to comment EPA-HQ-OAR-2002-0058-3213.1, excerpt 145 for EPA's authority to create subcategories.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-2702.1
Comment Excerpt Number: 50

Comment: Congress Contemplated and Approved Subcategorization.
The legislative history makes clear that Congress intended EPA to distinguish among classes, types and sizes of sources under three core circumstances: when differences among sources affect (1) the feasibility of air pollution control technology; (2) the effectiveness of air pollution control technology; and (3) the cost of control: The Senate Report clarifies that the Administrator should: take into account factors such as industrial or commercial category, facility size, type of process and other characteristics of sources which are likely to affect the feasibility and effectiveness of air pollution control technology. Cost and feasibility are factors which may be considered by the Administrator when establishing an emission limitation for a category under section 112. The proper definition of categories, in light of available pollution control technologies, will assure maximum protection of public health and the environment while minimizing costs imposed on the regulated community. However, in limited circumstances where a group of sources may share the characteristics of other sources in the category, the Administrator may establish subcategories for such sources. S. Rep. No. 228, 101st Cong., 1st Sess 166.

Thus, in the view of the Senate, the standard for establishing categories and subcategories is essentially the same, although the Administrator is cautioned not to make too rampant use of subcategories. The House Report similarly provides: "EPA may distinguish among classes, types and sizes of sources within a category or subcategory.... 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 measures, or to drive sources to the brink of shutdown." House Rep. No. 101-490, Part 1, at 328. In sum, while Congress intended the MACT program to achieve significant emissions reductions, it also intended EPA to be cognizant of the costs of control, and to ensure that the program did not cause significant economic hardship. One primary mechanism for achieving this goal is through the use of subcategories; subcategorization enables the Agency to account for the fact that distinctions among classes, types and sizes of sources may have a very real impact on the feasibility of a given control technology, the effectiveness of that control technology, and the cost of control.

Response: See response to comment EPA-HQ-OAR-2002-0058-3213.1, excerpt 145 for EPA's authority to create subcategories.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-2702.1
Comment Excerpt Number: 51

Comment: Variation of Emission Standards on the Basis of Fuel Type is Valid.
The only case to interpret the "classes, types and sizes" language that supports this interpretation. Sierra Club v. Costle, 657 F.2d 298 (D.C. Cir. 1981) recognized the broad discretion this language confers on EPA to create what in effect are subcategories of sources with differentiated emission standards. This decision interpreted identical statutory language found in the New Source Performance Standards (NSPS) provisions of § 111 of the CAA. Under the "classes, types and sizes" language, the Sierra Club v. Costle court upheld a variable NSPS S02 reduction requirement that was tied to a source's existing S02 emissions levels which, in turn, depended on the sulfur content of the facility's fuel. The Court noted that "[t]he required finding that must underlie a variable standard is much broader than a mere determination that uniformity is not achievable. Rather, EPA has the discretion to vary the standard upon finding that such a departure (from uniform control) does not undermine the basic purposes of the Act." Sierra Club v. Costle, 657 F.2d at 321 (quotations omitted). On this basis, the Court expressly upheld EPA's subcategorization of coal-fired power plants based on the sulfur content of fuel, finding that "[the text of the statute nowhere forbids a distinction based on sulfur." Sierra Club v. Costle, 657 F.2d at 319.

More generally, the Sierra Club v. Costle decision confirms EPA's discretion to set differentiated emissions standards for groups of sources within a category (i.e., for subcategories) even in instances where the strictest standard may be achievable by all sources. The court's analysis in

Sierra Club v. Costle has obvious relevance to an analysis of the authority granted to EPA through CAA § 112. Section 112 employs the same language as § 111 in defining when EPA may promulgate distinct emission standards for sources within a category or subcategory. The Supreme Court consistently has held that "when administrative and judicial interpretations have settled the meaning of an existing statutory provision, repetition of the same language in a new statute indicates, as a general matter, the intent to incorporate its administrative and judicial interpretations as well." Bragdon v. Abbott, 524 U.S. 634, 645 (1998). Therefore, § 112, which adopted § 111's terms almost ten years after the decision in Sierra Club v. Costle, must be understood to carry the settled meaning given to those terms by Sierra Club.

Response: See response to comment EPA-HQ-OAR-2002-0058-3213.1, excerpt 148 for further subcategorization by fuel type.
See response to comment EPA-HQ-OAR-2002-0058-3213.1, excerpt 145 for EPA's authority to create subcategories.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-2702.1
Comment Excerpt Number: 52

Comment: EPA's Past Practice Regarding Subcategorization is Consistent with the Proposed Subcategories.
EPA's past practice has been consistent with this interpretation of the Act. The Agency has subcategorized sources in numerous industrial categories. From this experience, it is possible to distill several principles that have guided the Agency's decision making with regard to creation of subcategories. First, EPA has determined that subcategorization is appropriate where sources use different processes, and those processes result in different types or concentrations of uncontrolled HAPs. Here, for example, the suite of HAPs emitted by solid-fueled boilers differs from that emitted by liquid-fueled boilers, which in turn differs from that emitted by gas-fueled boilers. For example, the types of metals emitted by solid-fueled boilers differs from the types of metals emitted by liquid-fueled boilers, and gas-fueled boilers typically emit little metals, but may emit more organic HAPs. Thus, subcategorization based on fuel type is appropriate because the different types of boilers emit different types of HAPs. The Agency also has subcategorized sources based on size, where size differences affect the performance of control technologies.

That is also the case here. Thus, subcategorization of boilers based on size, or infrequent utilization, also is consistent with EPA's past precedent and is appropriate because of the impact of these factors on the ability of these sources to maintain the same level of control as larger sources. Furthermore, the Agency has subcategorized sources where differences among sources affect the applicability of control technology. For example, EPA created subcategories in the 1999 polyether polyols production MACT standard, finding "Subcategorization was necessary due to the distinctively different nature of the epoxide and THF processes and its effect on the applicability of controls." Similarly, in the 1998 flexible polyurethane foam production MACT standard, EPA found that "Subcategorization was necessary to reflect major variations in production methods, and/or HAP emissions that affect the applicability of controls." Based on similar rationales, EPA created subcategories in the Group I polymers and resins MACT and the primary aluminum production MACT, and proposed to create subcategories in the polyurethane foam production MACT. Subcategorization based on fuel type is appropriate because the type of fuel affects the applicability of control technology.

EPA also has created subcategories in numerous cases where differences among sources affected the performance of control technology and, hence, the achievability of the MACT standard. For example, in the steel pickling MACT, EPA excluded specialty steel because the technology that is effective for removing acid gas (HCl) emissions from carbon steel manufacturing "may not be as effective" for removing acid gas (H2S04) emissions from specialty steel manufacturing. Similarly, the phosphoric acid manufacturing MACT subcategorized the submerged combustion process and the vacuum evaporation process because the "submerged combustion process is not amenable to the same level of control as is the vacuum evaporation process." In the leather finishing operations MACT, EPA "observed differences in achievable emission levels between the types of leather products produced ... [and therefore] we have established four different performance standards for the various leather products produced." And in the proposed secondary aluminum production MACT, EPA "examined the processes, the process operations, and other factors to determine if separate classes of units, operations, or other criteria have an effect on air emissions from emission sources, or the controllability of those emissions." In sum, EPA’s proposed subcategories are amply supported by the language of the statute, the legislative history, applicable case law and the Agency’s own past practices.

Response: See response to comment EPA-HQ-OAR-2002-0058-3213.1, excerpt 145 for EPA’s authority to create subcategories.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-2702.1
Comment Excerpt Number: 53

Comment: Need limited use subcategory for liquid or gas 2 units based on 10% annual Capacity factor or 1,000 hours/year as a threshold.
EPA should establish a subcategory for "limited use" units due to their significant differences from steady-state units. Limited use units should have a rated heat input greater than 10 MMBtu/hr with an annual average capacity factor of 10 percent or less. These units operate for short periods of time during the year and as such may experience relatively little SSM. The short run times would likely exacerbate the effect of startup/shutdown on 30 day averages. Because limited use units do not operate regularly, their emissions differ from average boilers operating for longer periods of time or near their design capacity. EPA has recognized that "units operate most efficiently when operated at or near their design capacity." 75 FR 32023-24. Based on their operating schedule, limited use units may or may not operate at or near their design capacity, but if they do it is for limited periods of time. Considering this, limited use units may operate for a

greater percentage of their total operating time inefficiently as compared to steady state units operating near design capacity.

Additionally, the short operating times of limited use units results in difficulties in effectively controlling emissions. As EPA noted in a 2004 response to comments document , based on the operating schedules of limited use units the agency could not identify a control technology for controlling organic HAP emissions. See EPA, Response to Public Comments on Proposed Industrial, Commercial, and Institutional Boilers and Process Heaters NESHAP, at 67 (Feb. 25, 2004). Considering these differences based on the operating schedule of limited use units, EPA should establish a subcategory for limited use boilers and process heaters. The subcategory should be defined to include units with a capacity utilization factor of 10 percent; or, by a 1,000 hours operating per year threshold.

Furthermore, EPA should adopt a work practices standard for the limited use subcategory. First, EPA's has acknowledged that there is no proven control technology for organic HAP emissions from limited use units. Second, limited use units, such as emergency and backup boilers, cannot be tested effectively due to their limited operating schedules. This is due to the fact that there is often no time to conduct performance tests on a unit operating in a limited capacity and because most EPA test methods require a unit to operate in a steady state. See Proposed 40 CFR 63.7520(d). Based on existing test methods, limited use units would have to operate for the sole purpose of being subjected to emissions testing. Such a result is counter to the general intent behind the CAA. EPA should therefore use its authority under section 112(h) and adopt a work practices standard for limited use units and not subject the subcategory to emissions testing or monitoring.

Response: Please refer to the preamble for discussion of the limited use subcategory.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-2702.1
Comment Excerpt Number: 54

Comment: EPA Should Create Additional Subcategories.
While CIBO supports EPA's efforts in creating subcategories, EPA has not sufficiently considered the vast array of units and their differences. Units including cyclone-fired boilers do not clearly fit in any of the proposed subcategories. These units vary to such an extent that achieving the emission standard for CO and dioxin/furan in any of the existing subcategories would likely not be feasible. EPA should consider creating a subcategory for units like cyclone-fired boilers that do not fit in other subcategories. Alternatively, EPA should provide clarification as to what subcategory they fall into and the emission standards they are required to meet. Furthermore, CIBO suggests that EPA create subcategories for coal-fired boilers so there is split between units rated at > 1000 MMBtu and units rated at < 1000 MMBtu. EPA should also create a subcategory for fire-tube boilers, including hybrids with water and fire tubes. These

units tend to burn biomass and there combustion is so different they should be classified as small.

Response: See response to comment EPA-HQ-OAR-2002-0058-2818.1, excerpt 18 for subcategorizing according to heat input size.
See response to comment EPA-HQ-OAR-2002-0058-2818.1, excerpt 18 for subcategorizing according to heat input size. See response to comment EPA-HQ-OAR-2002-0058-2916.1, excerpt 3 for subcategorizing firetube boilers. EPA determined that insufficient data and techical rationale were provided for a separate cyclone subcategory. According to the survey, 42 boilers checked the "cyclone" combustor design. However, most of these units checked another type of combustor design, so there were only 12 units (10 coal and 2 biomass) that were uniquely classified as cyclone boilers, but are currently classified in the stoker subcategory. These units range between 190 and 640 mmBtu/hr for coal-fired units and 4 to 160 mmBtu/hr for the two biomass units. There are limited data available for cyclone boilers, for example there are only two biomass cyclone boilers with available test data.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 55

Comment: Should the Agency be able to identify specific gases that, because of their composition (e.g., chlorine content), result in significant HAP emissions and, where the emissions from their combustion can be adequately characterized and it is feasible to control them, it could establish emission or fuel standards for those species when they are combusted in a boiler or process heater using the 112(d)(3) process. In that case, the Agency could establish a narrow subcategory as a legal basis for regulating such gases.

The majority opinion in the Brick MACT case does not address the possibility of subcategorization to address differences in the HAP content of raw materials. However, in his concurring opinion Judge Williams stated that EPA‘s ability to create subcategories for sources of different classes, size, or type (CAA section 112 (d)(1)) may provide a means out of the situation where the floor standards are achieved for some sources, but the same floors cannot be achieved for other sources due to differences in local raw materials whose use is essential. (Id. At 88485.9)

Recommendation: Where a HAP in fuel is emitted to the atmosphere through a boiler or process heater and it is feasible to characterize those emissions and where control is possible, the Agency should establish narrow subcategories to address those specific HAPs through 112(d) processes.

Response: See response to comment EPA-HQ-OAR-2002-0058-3213.1, excerpt 148 for further subcategorization by fuel type.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-2702.1
Comment Excerpt Number: 75

Comment: Additional subcategories are needed for new source standards.
The proposed new source standards are unrealistic and, if left unchanged, could seriously endanger the nation's long-term prospects for growth in the manufacturing sector. Reports we hear from suppliers of boilers and air pollution control systems are that they will not be able to supply commercial guarantees to meet the proposed standards. Additional subcategories which focus on the regional fuel supplies (Powder River Basin, Illinois Basin, Central Appalachian, etc) are needed to allow future boilers to be installed across the nation. For example, the top performer used to set the HCl standard for new coal-fired boilers is a boiler which burn sub-bituminous coal, which inherently has much lower chlorine content than eastern coals. A facility on the east coast should not have to meet standards that can be met only by burning a fuel only obtained from hundreds if not thousands of miles away.

Response: See response to comment EPA-HQ-OAR-2002-0058-2960.1, excerpt 61 for additional subcategory based on regional fuel availability or geographic location.

Commenter Name: Henry T. Graham
Commenter Affiliation: Louisiana Chemical Association
Document Control Number: EPA-HQ-OAR-2002-0058-2731.1
Comment Excerpt Number: 8

Comment: Include additional fuel oil burning flexibility in the final rule. Work practice standards are more appropriate for fuel oil burning at refinery locations and remote locations without access to natural gas. If EPA decides to proceed to set HAP emission limits on refinery oil units, the ten-percent allowance needs to be made on the collection of heaters and boilers subject to the standards instead of the individual pieces of equipment.

Response: See preamble for discussion of a non-continental unit subcategory.

See response to comments EPA-HQ-OAR-2002-0058-2840.1, excerpt 12 and EPA-HQ-OAR-2002-0058-2875.1, excerpt 9 for use of back up fuels within Gas 1 units and appropriateness of 10% fuel use limit.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)

Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 56

Comment: These comments relate primarily to refineries that combust residual and distillate fuel oil (this term includes distillate range intermediates combusted in some facilities) in process heaters and boilers, but also relate to other oil burning sources such as Alyeska‘s crude oil loading facility. Most oil combustion in the petroleum sector is in locations that are islands or in more remote parts of the United States, since it is those areas where natural gas is not available to balance the fuel supply generated at the location. It is important to note that these facilities burn oil because they must do so, even though it imposes much more complicated operating procedures AND it is significantly more costly than burning natural gas, were it available. This is the case even for combustion of residual fuel oil, which is less costly than ultra low sulfur diesel or No. 2 fuel oil.

Response: See preamble for discussion of a non-continental unit subcategory.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-2702.1
Comment Excerpt Number: 68

Comment: EPA's approach to subcategorizing the boilers and process heaters in the Gas 1 subcategory for purposes of establishing the potential floors in the preamble fails to account for units designed and operated to minimize emissions of NOx to comply with state and federal permit limits. Units operated to keep NOx levels low will have higher emissions of CO due to the need to minimize excess air to minimize thermal NOx. Thus, CO emissions from these units will be higher than boilers not designed or operated to keep their NOx emissions low and in compliance with permit limits. The CO floor level in the preamble for Gas 1 units ignores these design issues and any emission limits based on the potential CO floor level in the preamble would be difficult, if not near impossible, for these boilers to achieve while also meeting the required NOx permit limits. EPA has discretion to account for design characteristics when setting floors and should do so if work practices are not used.

Response: EPA has adjusted the CO limits, see preamble for a discussion of the revised CO limits. EPA has not promulgated any limits for the gas 1 subcategory.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 121

Comment: Combustion systems for industrial boilers and process heaters are designed first to accomplish a specific duty converting chemical energy to heat to produce steam for process heat and/or electricity generation, pre-heating a hydrocarbon feed for a process reactor, cracking and reforming hydrocarbons, etc. Boilers and process heaters typically have two main sections: a furnace or firebox; and a convective heat exchange section. Combustion of the fuel takes place within the combustion chamber (furnace or firebox). Tubes are carefully placed along the walls or in other arrangements in the furnace to receive large amounts of heat radiating from the flames and surrounding surfaces spread over just the right amount of surface area to accomplish the furnace duty: boil water, crack hydrocarbons, etc. The combustion chambers and burners are designed to fit the flames within the furnace without impinging on the tubes, while maintaining complete combustion, low emissions and oxidizing atmospheres. Roughly 50 to 70 percent of the total heat exchanged in a boiler or process heater occurs in the furnace, depending on the design. Combustion products and gases leave the radiant furnace at temperatures of approximately 1200 to 2000 0F. At these temperatures, radiative heat transfer is lower and convective heat transfer is more efficient. Gases from the furnace then pass through tightly packed tube banks to maintain higher gas velocities for more efficient heat transfer. Gases typically leave the convective heat exchanger at temperatures of approximately 500 to 800 0F.

Industrial boiler designs vary with size, fuel and steam use. Smaller units may be packaged, meaning complete, shop-assembled units that are small enough to transport complete by truck or rail. This can result in longer, narrower combustion chambers to limit the overall width of the unit for transport. Larger units may be field erected, where sections or modules are shipped to the site and final construction and assembly occurs at the facility. The shape, size and temperatures of combustion chambers vary tremendously among designs, depending on duty and fuels (e.g., Figure below). Because of these variations, the combustion environment also varies in terms of temperatures, residence time and mixing. Burners are designed for specific applications to complete combustion and fit the flames within the furnace without impinging on the furnace walls and tubes while delivering heat and producing low emissions efficiently.

[See submittal for image of examples of the variety of different process heater furnace configurations. [Footnote: Baukal, C.E. and Schwartz, R.E. The John Zink Combustion Handbook, CRC Press, Danvers, MA, 2001.]]

Response: See response to comment EPA-HQ-OAR-2002-0058-2818.1, excerpt 18 for subcategorizing according to heat input size.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 127

Comment: Low-NOx burner (LNB) designs for gas-fired boiler applications manipulate the mixing and stoichiometry within the flame to minimize thermal NOx formation. Staged combustion burner designs establish a fuel-rich zone for the initial phase of combustion, and then add air at a later stage in the outer regions of the flame. In the initial phase of fuel-rich combustion, there is not sufficient oxygen available to form significant amounts of NOx, and in the secondary phase, the flame is much cooler, which also inhibits thermal NOx formation. Ultralow NOx gas burners may also induce recirculation of combustion products into the initial and intermediate combustion stages, decreasing peak flame temperatures and reducing oxygen availability. "Lean premix" burners premix a portion of the fuel and air and initially combust under fuel-lean conditions, adding the balance of fuel and air downstream in a staged manner. This reduces peak flame temperatures in the initial combustion stage that lead to "prompt NOx" formation while also minimizing thermal NOx formation. These improvements in NOx emissions typically are accompanied by narrower limits of fuel-air ratio and turndown for safe operation (to maintain flame ignition stability). However, low-NOx and ultralow-NOx burners often operate with CO emission up to 10 ppmvd in the upper part of the load range. At mid loads, the CO begins to increase near 50 ppmvd, and at low loads, it may exceed 100 ppmvd. These low-NOx burners will not be able to achieve CO emissions as low as 2 ppmvd while maintaining safe operating conditions.

EPA recognizes this effect in its emission calculation guidance. The Agency explains:

"The presence of CO in the exhaust gases of combustion systems results principally from incomplete fuel combustion. Several conditions can lead to incompletecombustion, including insufficient oxygen (O2) availability; poor fuel/air mixing; cold-wall flame quenching; reduced combustion temperature; decreased combustion gas residence time; and load reduction (i. e., reduced combustion intensity). Since various combustion modifications for NOx reduction can produce one or more of the above conditions, the possibility of increased CO emissions is a concern for environmental, energy efficiency, and operational reasons."

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Response: See response to comment EPA-HQ-OAR-2002-0059-2702.1, excerpt 68 for additional subcategory to distinguish between units with low NOx burners.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 23

Comment: 63.7499 lists the subcategories of boilers and process heaters to which the proposed rule applies. We have a general concern with the subcategory list relative to gas and liquid combustion.

On page 30216 of the preamble, EPA explains the data were sufficient for determining that a distinguishable difference in performance exists based on unit design type. Therefore, because different types of units have different emission characteristics which may influence the feasibility or effectiveness of emission control, they should be regulated separately (i.e. subcategorized). Accordingly, we propose to subcategorize boilers and process heaters based on unit design in order to account for these differences in emissions and applicable controls.

While we agree with the Agency‘s conclusion that there are differences in emissions and applicable controls for gas- and liquid-fired boilers and process heaters, we do not believe unit design is the best way to distinguish among these differences. Many boilers and process heaters are designed to burn multiple fuels and many units that were originally designed for one fuel now burn a different fuel. In general, a boiler or process heater designed for a particular gas or liquid can change to another gas or liquid with relatively minor changes, at the most burner and feed system changes. Any boiler or process heater designed to burn Gas 1 (Natural Gas/Refinery Gas) can also burn Gas 2 (Other Gas) or vice-versa and many units originally designed to burn liquids have been modified to burn gas. Thus, the design fuel does not reflect the current fuel situation for gases and liquids. For units designed to burn both liquids and gases, the unit‘s design provides no basis at all for assigning the unit between the gas and liquid subcategories. Thus, many questions arise from using design as the basis for subcategory assignment for these fuels.

We believe the reasonable basis for distinguishing between gas and liquid subcategories is the fuel they actually burn. Except as discussed in the next paragraph, we recommend using the past calendar years as the basis with appropriate consideration of potential changes in subcategory, as discussed in our next comment. Using any type of rolling basis or a time period of less than a year would be a recordkeeping and compliance nightmare with no real regulatory advantage. A calendar year basis is consistent with the basis used for assigning storage vessels and distillation units under Subpart CC.

Recommendation: Base subcategory assignment on the fuels burned in the previous calendar year rather than on the design basis for the unit.

Response: See final rule and preamble for discussion of how units are assigned to subcategories and provisions available to switch subcategories.

Commenter Name: Ben Brandes
Commenter Affiliation: National Mining Association
Document Control Number: EPA-HQ-OAR-2002-0058-2787.1
Comment Excerpt Number: 10

Comment: Industrial boilers that have specialized uses and are therefore operated less frequently should be listed in a separate subcategory. Such auxiliary boilers are often operated primarily during plant startups, and as such emit very low levels of HAPs. These boilers should be categorized as those with a 10 percent capacity factor for the maximum hourly heat input, and should be subject to a work practice standard under Section 112(h) of the CAA.

Response: Please refer to the preamble for discussion of the limited use subcategory.

Commenter Name: Douglas A. McWilliams
Commenter Affiliation: American Municipal Power
Document Control Number: EPA-HQ-OAR-2002-0058-2808.1
Comment Excerpt Number: 10

Comment: Small municipal utilities serve a unique and essential role in both the electric industry as a whole and in their communities. As such, these boilers are easily distinguishable from the mass of other boilers and process heaters covered by the Proposed Rule. Both the many benefits provided by small municipal generators and the unique restrictions and challenges they face justify EPA's use of section 112(d)(1)'s subcategorization authority. Local generating facilities are an important component of the mix of electric power suppliers in existence today. They provide numerous, unique benefits to the public including:
Reducing power grid congestion and boosting reactive power;
Increasing the reliability of the electric system;
Increasing the ability of the electric system to meet peak demand;
Providing valuable protection against wholesale electricity price spikes;
Mitigating the impact of regional power failures;
Meeting demand in transmission-constrained "load pocket" areas;
Reducing the vulnerability of the electric grid;
Supplying power to important municipal functions;
Providing high quality jobs to local residents;
Keeping funding in local communities which, in turn, enhances the local economy;
Supplying ideal test sites for the implementation of new energy production technologies;
Increasing energy efficiency through reduction of line losses; and
Enhancing "yardstick competition," thus allowing better assessments of the performance of others in the industry.

These many unique benefits of municipal power generation are sufficient to justify subcategor. However, the unique restrictions and challenges laced by these uenerators further con lirtit the need for a municipal utility subcategory. Such restrictions include:
Legal restrictions prohibiting Ohio municipal generators from selling more than 33% of their kilowatt hours outside municipal limits;
Practical requirements that municipal generators dedicate a portion of their capacity to municipal functions;
The inability of municipal power generators to spread capital and operating costs over broad customer bases;
Constraints on the ability of local communities to finance major capital projects;

Major diseconomies of scale with respect to pollution control equipment on these small electric units, vis-à-vis larger utility units;
Many small municipal electric utility boilers are operated on a "peaking" basis, far less than their operating capacity, forcing these municipalities to spread major capital compliance costs over an even smaller amount of sales; and
Unique political pressures as municipally owned entities.
In addition to the legal constraints that uniquely impact small municipal power generators, the Proposed Rule presents a serious practical problem. Many municipal generation facilities are located in the heart of small towns. Because these towns often literally "grew-up" around these facilities, there is often no way to physically accommodate the substantial expansion needed for new add-on control devices. In many cases, it will be impossible or prohibitively expensive to relocate neighboring facilities. These communities would thus be limited to attempting to retrofit their existing equipment in the limited remaining space. In some cases, retrofitting will be impossible. Where such retrofitting is possible, associated capital costs are likely to increase exponentially. In fact, in nearly all cases the sole viable option will be to shut down.

Their small entity status further distinguishes municipal utilities from the mass of other boiler operators. SBREFA recognizes small governments and small utilities as deserving of special consideration and protection from regulatory impacts. Indeed, in this rulemaking, the SBREFA Panel recommended certain accommodations for small entities - including the establishment of HBELs. Given the financial and legal constraints detailed above, those recommendations should be heeded.

Response: See response to comment EPA-HQ-OAR-2002-0058-2795.1, excerpt 1 for additional subcategory for small municipal utilities or subcategorizing according to sector.

See response to comments Document Control Number: EPA-HQ-OAR-2002-0058-2601 Comment Excerpt Number: 3 for assessment of economic impact.

Commenter Name: Thomas Bakk
Commenter Affiliation: State of Minnesota Senate
Document Control Number: EPA-HQ-OAR-2002-0058-2950
Comment Excerpt Number: 12

Comment: Many facilities, including Minnesota forest products industries, have backup boilers that operate only when the primary units are down due to malfunction or maintenance. Typically, back-up boilers operate at 10% or less of annual capacity. The cost to upgrade a small package boiler is estimated by AF&PA to be $10 million. It is not cost-effective to add-on expensive pollution control equipment for sources that operate at 10% or less annually. In addition, testing protocols would require operation when the boilers are not needed. EPA should include a subcategory for limited use boilers, or a de minimis applicability threshold for small or limited use units.

Response: Please refer to the preamble for discussion of the limited use subcategory.

Commenter Name: Douglas A. McWilliams
Commenter Affiliation: American Municipal Power
Document Control Number: EPA-HQ-OAR-2002-0058-2808.1
Comment Excerpt Number: 13

Comment: As EPA has recognized, "[black-up or emergency units only operate if another boiler that is the regular source of energy or steam is not operating (for example due to a shutdown for maintenance and repair)." Revised MACT Floor Analysis (Feb. 2004) (EPA-HQ-OAR-20020058-0602). Moreover, these "infrequently operated units typically operate 10 percent of the year or less" [Footnote: This number was calculated using the prior database. For completeness of the administrative record, therefore, we would request that this database be made part of the current docket.], but "[t]hese limited use units, when called upon to operate, must respond without failure and without lengthy periods of startup." 69 Fed. Reg. at 55232. EPA has already recognized that, based on these facts, "their use and operation are different compared to typical industrial, commercial, and institutional boilers" and that "such limited use units should have their own subcategory." Id. Although EPA cannot reverse that decision without a reasoned explanation, the Proposed Rule offers no information on how or why it now omits a limited use subcategory. EPA does not mention either the limited use nature of many boilers or the fact that these boilers must undergo extensive maintenance and readiness

testing despite long periods of disuse in order to "when called upon to operate . . . respond without failure and without lengthy periods of startup. 69 Fed. Reg. at 55232. AMP encourages LP A to remedy this omission by returning the limited use subcategory to the final Boiler MACT rule.

Response: Please refer to the preamble for discussion of the limited use subcategory.

Commenter Name: Douglas A. McWilliams
Commenter Affiliation: American Municipal Power
Document Control Number: EPA-HQ-OAR-2002-0058-2808.1
Comment Excerpt Number: 14

Comment: Failure to create a limited use subcategory is inconsistent with EPA’s decision to rely on similar factors to justify an emergency use subcategory in the recently promulgated MACT for compression-ignition reciprocating internal combustion engines ("CI RICE"). See National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines, 75 Fed. Reg. 9648 (Mar. 3, 2010). In that rule, EPA recognized that stationary existing CI RICE should be divided into non-emergency and emergency categories "in order to capture the unique differences between these types of engines." Id. at 9650.
Like the limited use boilers described in the 2004 Boiler MACT rule, EPA recognized that emergency CI RICE are required to operate infrequently and for relatively short periods of time,

and so must be kept in working order for prolonged periods when they are not operating. See Subcategorization of Stationary Reciprocating Internal Combustion Engines <500 HP (May 15, 2006) (EPA-HQ-OAR-2005-0030-0012). Some of the specific factors identified by EPA in this memorandum are particularly salient. For example, EPA acknowledged that these CI RICE would need to operate when "electric power from the local utility is interrupted or has become unreliable" which, with the exception of "major catastrophes" would be for short periods of time. Id. at 5. In addition, as "emissions occur only during emergency situations or for a very short time to perform maintenance checks and operator training," EPA found that "[e]missions from these units are expected to be low on an annual basis.” [Footnote: Id. While these criteria focus on an "emergency use" subcategory, it is important to note that the limited duration of the use, not the purpose for using the CI RICE is the key issue. For example, the same rule also creates a subcategory for "black start" engines (engines used to start a turbine generator), which operate during both "emergency and high demand days." 75 Fed. Reg. at 9662.]

These same factors apply to limited use boilers. First, limited use boilers are put into service only during shutdown of the main boiler or "when electric power from the local utility is interrupted or becomes unreliable,"9 neither of which generally requires the limited use boiler to operate more than a short period of time. Second, because of their limited use during the year, "[e]missions from these units are expected to be low on an annual basis." Id. Third, like emergency CI RICE, limited use boilers operate for only a small portion of the year, typically “10 percent of the year of less.”

Without a limited use subcategory, such infrequently operated units would have to comply with emission limits set by units operating on a continuous basis at or near their capacity. That is unreasonable because, as EPA has already acknowledged, "[c]ombustion units operate most efficiently when operated at or near their design capacity. The combustion efficiency tends to decrease as the unit’s load (steam production) decreases." 75 Fed. Reg. at 32023. Even if a limited use boiler is called upon to operate at maximum capacity, it can take hours or days to ramp up from a cold start and a similar period of time to cool down. For a unit operating for as little as 15 hours in a month, this could be a substantial portion or even all of the time during which the boiler is operating. As a result, limited use boilers will seldom be operating at maximum capacity or maximum efficiency. Without a limited use subcategory, the regulations will be comparing these boilers to ones EPA has already recognized are operating under more efficient circumstances. This is both unreasonable and arbitrary.

Response: Please refer to the preamble for discussion of the limited use subcategory.

Commenter Name: Douglas A. McWilliams
Commenter Affiliation: American Municipal Power
Document Control Number: EPA-HQ-OAR-2002-0058-2808.1
Comment Excerpt Number: 15

Comment: The problem is further amplified by EPA’s current decision to include periods of startup and shutdown in the MACT floor analysis. [Footnote: Continuous emission monitoring data is not available for all pollutants in the database. To the extent that emission limits are based on stack test data that does not consider SSM events, EPA is obliged to use other available

"emission information" which may include calculations based on an operator's knowledge and engineering analysis. This emission information should be used to properly incorporate SSM variability into the MACT floor analysis.] EPA found in the Proposed Rule that including these periods will be justified because "the standards that we are proposing are daily or monthly averages" and because "[b]oilers, especially solid fuel-fired boilers, do not normally startup and shutdown more [than] once per day." [Footnote: Even this appears to be a vast overstatement. Taking all boilers and process heaters reporting startups per year in
EPA's Materials Combusted Table, the average is only 44.7 per year, including small units and process heaters] Id. at 32013. Moreover, EPA found that "[p]eriods of startup, normal operations, and shutdown are all predictable and routine aspects of a source's operation." Id. These findings do not apply to limited use boilers. First, these boilers will seldom be called upon to operate during an entire 30-day period and so cannot practically average emissions over a month, even assuming that testing equipment and personnel are ready immediately upon startup. Even a daily average is insufficient for the 15-hour months that were characteristic of the Painesville limited use boiler. Second, since limited use boilers are only operated in emergencies or when another boiler is down, their use is neither predictable nor routine.
EPA should not require limited use boilers to comply with standards set by the best operated 12% of a group of more efficient units operating with the benefit of a 30-day averaging period during periods of planned usage. To do so would create a technically infeasible limit.

Response: Please refer to the preamble for discussion of the limited use subcategory.

Commenter Name: Quinlan J. Shea
Commenter Affiliation: Edison Electric Institute
Document Control Number: EPA-HQ-OAR-2002-0058-2755.1
Comment Excerpt Number: 15

Comment: EPA should promulgate work practice standards for utility auxiliary boilers.

Electric utilities operate auxiliary boilers that will be subject to the IB MACT because they are not steam generating units that produce electricity. Auxiliary boilers operate infrequently – normally only during plant startups – and combust either natural gas or distillate fuel. As a result, HAP emissions from auxiliary boilers are exceedingly low and therefore do not pose any risk to public health.

Under the proposed IB MACT, gas-fired auxiliary boilers are subject to work practice standards requiring an annual tune up. By contrast, the proposed IB MACT requires oil-fired auxiliary boilers to comply with stringent emission limits and demonstrate compliance with those limits by following expensive monitoring requirements. The distinction between these two different types of auxiliary boilers is unnecessary and does not lead to any significant environmental benefits.

EPA should create a limited use subcategory for auxiliary boilers combusting distillate fuel that would subject those units to the same work practice standards as gas-fired units. The limited use subcategory should have a 10% capacity factor threshold. Eligibility for this subcategory would be determined based on 10% of the maximum hourly heat input of the boiler multiplied by 8760 hours per year.

Response: Please refer to the preamble for discussion of the limited use subcategory.

Commenter Name: Jeffrey R.Klieve
Commenter Affiliation: Monsanto Company
Document Control Number: EPA-HQ-OAR-2002-0058-2754.1
Comment Excerpt Number: 16

Comment: Additional Subcategories (75 Fed. Reg. 32027)

Monsanto is concerned that there are too few subcategories in the proposed rule for the diverse boiler types in operation around the United States. The USEP A has legal authority to expand the number of subcategories in developing MACT regulations.

Response: See response to comment EPA-HQ-OAR-2002-0058-2987.1, excerpt 3 for general requests for additional subcategories.
See response to comment EPA-HQ-OAR-2002-0058-3213.1, excerpt 145 for EPA's authority to create subcategories.

Commenter Name: Douglas A. McWilliams
Commenter Affiliation: American Municipal Power
Document Control Number: EPA-HQ-OAR-2002-0058-2808.1
Comment Excerpt Number: 25

Comment: If considering variability in fuel quality across di Iferent types of fuel within a single subcategory is too difficult, that may be an indication that EPA should subcategorize based on fuel types down to specific fuels and materials. Additional subcategorizing within fuel groups appears particularly warranted here, given that EPA has (rightfully) ruled out fuel switching as impossible for many regulated sources.

Response: See response to comment EPA-HQ-OAR-2002-0058-3213.1, excerpt 148 for further subcategorization by fuel type.

Commenter Name: Chris M. Hobson
Commenter Affiliation: Southern Company
Document Control Number: EPA-HQ-OAR-2002-0058-2741.1
Comment Excerpt Number: 57

Comment: For units with limited service such as electric utility auxiliary boilers, EPA's proposed work practice standards for units that burn natural gas may be more than is needed, but it is neither cost prohibitive nor technical infeasible. On the other hand, the proposed compliance provisions appear unreasonable for limited use boilers that burn distillate oil.19 First, the cost for sources with oil-fired auxiliary boilers to install and maintain the control equipment (and potentially monitoring equipment) necessary to meet the proposed emissions standards would be excessive, particularly for a unit that may operate with an annual capacity factor less than 10%. In fact, many electric utilities will likely retire such boilers and lease temporary boilers for unit start-up, which are exempt under the proposed rule, rather than invest in the controls necessary to meet the proposed limits. This provides no environmental gain since emissions from the temporary boilers would be the same if not worse than the existing boilers. Second, because the demand for an auxiliary boiler to operate is almost impossible to forecast, it is almost a certainty that each auxiliary boiler would have to be operated some time during each year for the sole purpose of emission testing. Such an outcome would result in a number of unintended, negative consequences: (1) unnecessary air pollutants would be generated; (2) unnecessary carbon emissions would occur; and (3) a valuable and not unlimited resource (low sulfur diesel fuel) would be wasted.

RMB recommends that EPA create a separate subcategory for limited use, oil-fired boilers and suggests that the work practice standard currently applied to gas-fired boilers (boiler tune-up) be applied in lieu of emissions standards. We believe that the application of a work practice standard is justified in this case due to the cost impact.

RMB notes that the vacated IB-MACT rule contained several limited-use subcategories, including new/reconstructed limited use solid fuels, new/reconstructed limited use liquid fuels, and new/reconstructed limited use gaseous fuels, and existing limited use solid fuel. [Footnote: Limited use subcategories were not necessary for existing gas and liquid fire units because EPA had determined that the MACT floor for these units was "no emissions reductions."] The limited use subcategory in the vacated rule applied to sources with an annual capacity factor of 10% or less, such as auxiliary boilers at electric power plants. While EPA embraced the use of limited-use subcategories in the vacated rule, they have not provided any justification for eliminating these subcategories in the proposed rule.

Response: Please refer to the preamble for discussion of the limited use subcategory.

Commenter Name: John W. Myers
Commenter Affiliation: Tennessee Valley Authority
Document Control Number: EPA-HQ-OAR-2002-0058-2963.1
Comment Excerpt Number: 1

Comment: TVA, as well as most other utilities, operates auxiliary boilers that will be subject to the proposed IB MACT rule because they do not generate steam for producing electricity. In TVA's case these auxiliary boilers are used for startups to provide steam for steam-driven equipment such as fans and pumps until the main boiler comes on line. In other instances auxiliary boilers may be utilized to provide freeze protection when all electric generating units at a site are down. Many of these boilers operate infrequently with some not being used for years. All of TVA's auxiliary boilers are fired by natural gas or No. 2 fuel oil. Two have heat input capacities >250 MMBtu/hr, two are >100 MMBtu, seven are >10 MMBtu/hr and three are <10 MMBtu/hr.

In the proposed rule units burning natural gas are only required to perform a tune-up and the distillate fuel oil units are subject to emissions testing, monitor installations, emissions averaging and reporting. These additional requirements for distillate fuel units are unnecessary and produce little, if any, environmental benefit for limited use boilers.

It is recommended that EPA establish a limited use subcategory for distillate fuel boilers that are operated only occasionally and regulate these units under the same work practice standards proposed for gas-fired units. Distillate fuel units meeting this limited use definition should have a 10% capacity factor threshold, based on 10% of the maximum hourly heat input of the boiler on an annual (8760 hours) basis.

Response: Please refer to the preamble for discussion of the limited use subcategory.

Commenter Name: Jim Weeks
Commenter Affiliation: Michigan Municipal Electric Association
Document Control Number: EPA-HQ-OAR-2002-0058-2795.1
Comment Excerpt Number: 1

Comment: Subcategory for Municipally- Owned Electric Units: EPA should create an additional subcategory of covered units for municipally-owned electric units, because of the unique technical and institutional issues associated with these units. Only electric utilities have an obligation to serve under law, unlike other industry sectors. Public power systems are distinct from investor-owned utility systems because public power systems are (with a very few exceptions) small, non-profit, local government entities that are covered by the protections of the Small Business Regulatory Enforcement Fairness Act, including the recommendations of the Small Business Advocacy Panel convened for this EPA rulemaking. Further, because public power systems tend to rely heavily or exclusively on one generating plant for most or all of its electric generation and service, those public power units are essential for electric reliability in their jurisdictions. Moreover, public power entities provide electricity on a cost-of-service basis without any profit markup. which means that the costs of difficult MACT compliance will be borne directly by the customers of these struggling Michigan economies.

The different structures, characteristics and functions of public power systems and their small electricity generating units make these units distinct from non-public power systems, and this justifies the creation of an additional MACT sub-category for municipally-owned and — operated electricity generating units that, without a subcategory, will suffer disproportionate impacts from this rule. For this municipal utility sub-category, EPA should develop reasonable emissions limitations and standards based on the best-performing sources within that subcategory — particularly monitoring flexibility and health-based limitations for acid gases as recommended by the Small Business Advocacy Panel.

Response: The EPA sees no technical or legal justification for creating a separate subcategory for small municipal utilities or subcategorizing according to sector. Boilers at municipal utilities fire the same type of fuels, have the same type of combustor designs, and can use the same type of controls as other units in the large subcategory. We would also like to clarify that subcategories were developed based on combustor design and not on industrial sector. Also, had we gone beyond-the-floor, we would have considered cost in the final determination. Since we did not go beyond-the-floor level of control, cost did not play a role in the analysis. See response to comments Document Control Number: EPA-HQ-OAR-2002-0058-2601 Comment Excerpt Number: 3 for assessment of economic impact.
EPA thanks the commenters for providing their statements of potential effects of the rule to small communities. EPA has incorporated several monitoring flexibilities and work practices into the rule to help reduce the burden on certain small entities.

Commenter Name: Winslow Sargeant
Commenter Affiliation: U.S. Small Business Administration
Document Control Number: EPA-HQ-OAR-2002-0058-2916
Comment Excerpt Number: 2

Comment: EPA Should Have Adopted Additional Subcategories

SERs recommended that EPA adopt the following subcategories for boilers:

Fuel type (including coal rank, bagasse, biomass by type, and oil by type);
Boiler design type (e.g. fluidized bed, stoker, fuel cell, suspension burner);
Duty cycle;
Geographic location;
Boiler size;
Burner type (with and without low-NOx burners);
Process heaters;
Limited use boilers.

Subcategorization as outlined above was a primary flexibility concern of the SERs during the SBREFA panel. The panel report states that, "SERs commented that subcategorization is a key concept that could ensure that like boilers are compared with similar boilers so that MACT floors are more reasonable and could be achieved by all units within a subcategory using appropriate emission reduction strategies." [Footnote: SBAR Panel Report at 22.] While the Panel did recognize that the entire list of potential subcategorizations asked for by SERs was not practicable because of overlap in the categories, EPA should have proposed some additional subcategories as recommended by the panel. EPA has almost complete discretion to establish any subcategories "as appropriate." [Footnote: Section 112(c)(1) of the Clean Air Act. EPA may distinguish among classes, types and sizes of sources within a category. House Report No. 101-

490, Part 1 at 328.] Without the additional subcategories, it increase the cost and difficulty for many small sources to meet emissions standards when they are placed in a category that is driven by the efficiency of very different boiler units running on different fuels, under different duty cycles, and most likely designed for very different purposes. In many cases, forcing boilers into categories where they do not belong will require costly investments to meet standards that are simply not achievable for certain boiler and fuel types, while yielding small or insignificant environmental benefits. In particular, it is very hard to justify why limited use boilers should be subject to the same standards as other boilers. [Footnote: This contrasts strongly with the treatment of the recent MACT standards adopted for limited use reciprocating diesel and spark ignition engines, promulgated by the Agency in 2010, creating a separate category for limited use engines and emergency use engines (e.g engines that run less than 24 hours per year). EPA does not explain the disparate treatment.] EPA did include a "limited use" subcategory for boilers with average capacity factors of 10% or less in the 2004 boiler rule.

Response: See response to comments EPA-HQ-OAR-2002-0058-2916, excerpt 2 and EPA-HQ-OAR-2002-0058-2702.1, excerpt 54 for subcategories based on design type, and for cyclone, firetube, and hybrid watertube-firetube boilers.
See response to comment EPA-HA-OAR-2002-0058-2808.1, excerpt 12 for further subcategorization based on coal rank.
Please refer to the preamble for discussion of the limited use subcategory.
See response to comment EPA-HQ-OAR-2002-0058-1841.1, excerpt 2 for bagasse boiler subcategory.
See response to comment EPA-HQ-OAR-2002-0058-3213.1, excerpt 148 for further subcategorization by fuel type.
See response to comment EPA-HQ-OAR-2002-0058-2960.1, excerpt 61 for additional subcategory based on regional fuel availability or geographic location.
See response to comment EPA-HQ-OAR-2002-0058-2818.1, excerpt 18 for subcategorizing according to heat input size.
See response to comment EPA-HQ-OAR-2002-0058-2912, excerpt 2 for separate subcategories for process heaters and boilers.
See response to comment EPA-HQ-OAR-2002-0059-2702.1, excerpt 68 for additional subcategory to distinguish between units with low NOx burners.

Commenter Name: David Z. Skolasinski
Commenter Affiliation: Cliffs Natural Resources
Document Control Number: EPA-HQ-OAR-2002-0058-2881.1
Comment Excerpt Number: 2

Comment: Establishing Emission Limits For Large Heating Boilers Is Unnecessary And The Requirement For Demonstrating Compliance With Emission Limits Is Impractical
Cliffs operates a number of both large and small oil-fired heating boilers at its mining facilities. The boilers provide heat to mine facility buildings including offices, ore processing facilities, maintenance shops, warehouses, and other similar types of buildings. The boilers typically operate during October through May of each year. During this period, the boilers provide heat to

the buildings on an as needed basis. Cliffs requests that EPA reconsider the establishment of emission limits and associated stack testing for seasonally operated, large (10 MMBtu/hr or greater) oil-fired and possibly also solid fuel fired heating boilers and instead require only annual tune-ups similar to those for large gas-fired boilers. The rationale for this request and recommendation is set forth below.

Depending on the boiler design and type of oil burned, the boilers operate in one of two ways. In one case the boilers operate similar to a furnace in a residential home. When the building temperature drops to a predetermined level the boiler turns on and operates until the desired temperature in the building is achieved and then the boiler shuts off. During the fall, spring, and occasional warm winter periods, the boilers typically operate on a cycle of 15 minutes on followed by 45 minutes off. During the colder winter months the boilers typically operate on a cycle of 15 minutes on followed by 20 minutes off.
Boilers that burn heavier liquid fuel such as No. 6 oil remain on continuously but operate at some percent of capacity depending on the level .of heat called for in the buildings. During the fall and spring months the boilers may operate at only 25% capacity while during the winter months they may operate at 75% - 100% of capacity. However, the daily operating rate of the boiler is adjusted manually depending on the weather and the heat requirements in the building, and the operating rate typically also varies between day and night. There are also times especially in the fall and spring when occasional warm days occur that the boiler operations are reduced to essentially an idle. In all cases, any heat produced must be delivered to the building heating system.

Response: The EPA sees no technical or legal justification for creating a separate subcategory for seasonal units. However, a limited use subcategory has been created for units operating less than 876 hours per year. It was developed to represent a specific type of boiler, those used as backup, emergency, or peaking units that operate infrequently. The subcategories at proposal and in the final rule are based on differences in fuel states, combustor types, and use of boilers and process heaters. If a seasonally operated boiler meets the definition of a limited use unit, it would fall under this subcategory. The EPA, however, sees no justification for changing the limited use capacity factor. A review of the information gathered on boilers also shows that a number of units operate as backup, emergency, or peaking units that operate infrequently. The boiler database indicates that these infrequently operated units typically operate 10 percent of the year or less. These limited use boilers, when called upon to operate, must respond without failure and without lengthy periods of startup. Since their use and operation are different compared to typical industrial, commercial, and institutional boilers, we decided that such limited use units should have their own subcategory.

Commenter Name: Ann W. McIver
Commenter Affiliation: Citizens Energy Group
Document Control Number: EPA-HQ-OAR-2002-0058-2875.1
Comment Excerpt Number: 2

Comment: Citizens believes that the use of subcategories is appropriate and supports EPA’s decision to identify subcategories in the proposed rule. Combustion design and type of combustor, as well as fuel, influence the emissions produced during combustion. However, Citizens requests that EPA add a subcategory for limited use boilers and process heaters to the previously identified subcategories.
In the 2004 final rule, EPA promulgated a limited use subcategory. This subcategory was defined generally as units with annual average capacity factors less than ten percent (10%). Within the universe of potentially affected units, many are operated as stand-by or redundant capacity. Such units are reserved for use during periods when circumstances mandate the need to provide steam in order to preserve conditions within the distribution system. These boilers are often equipped with coils to maintain internal metal temperatures, as well as boiler drum pressure and temperature, to allow for quick response following the combustion safety purge.

Citizens believes that the justification for the limited use subcategory continues to exist, and that the promulgation of a limited use subcategory will not compromise the environmental benefits associated with this rulemaking.

Response: Please refer to the preamble for discussion of the limited use subcategory.

Commenter Name: Gordon M. Smith
Commenter Affiliation: Mitsubishi Polyester Film, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2912
Comment Excerpt Number: 2

Comment: Subcategorize Boilers and Process Heaters. Boilers typically are designed differently than process heaters, operate differently, have historically been regulated differently and typically have higher heat duties. Additionally, boilers all operate in a narrow range of firebox temperatures, while process heaters operate over a very wide range, resulting in a much broader range of emissions from process heaters than from boilers.

Typically process heaters are smaller than boilers, since process heater duty is matched to the process need, while boiler duty is matched to site steam demands. Because heat distribution is critical in process heaters, they typically have many smaller burners and those burners can be located in the floor, the walls or even in the roof. Because they have many burners and lower total firing, oxygen control is typically not as sophisticated on a process heater as on a boiler. Process heaters can and do vary substantially in operating rate, but over longer time spans than boilers, because process heat demands do not vary as quickly as steam demands.

Process heaters are designed for the process that they support. One key variable is firebox (bridgewall) temperature, which can vary in different processes by 600 or more degrees because of the heat needed for a particular type of process. Design differences in process heaters to support the functions of different units lead to differences in residence time and temperature, both of which have a significant impact on emissions.

It is clear from simple inspection that combustion conditions in boiler and process heaters are not the same and that there emissions and control approaches are not be the same. It is obvious that there should be separate subcategories for each of these combustion unit types for each fuel category.

Response: The EPA does not see justification for creating a separate subcategory for both process heaters and boilers. Most process heaters are firing refinery gas, which is covered under the work practice standard. Therefore there is not a utility in separating this subcategory as neither subcategory is subject to emission limits and insufficient remaining data to establish separate MACT floors for boilers vs. process heaters.

Commenter Name: Byron T. Burrows
Commenter Affiliation: Tampa Electric Company
Document Control Number: EPA-HQ-OAR-2002-0058-3129
Comment Excerpt Number: 2

Comment: Section 112(d)(1) of the CAA allows the Administrator to distinguish among "classes, types, and sizes of sources" in establishing MACT standards. In providing EPA discretion to create subcategories, § 112(d)(1) does not restrict subcategorization to cases where the "class", "type" or "size" factors affected HAP emissions. The provision merely requires EPA to establish regulations for each category or subcategory on the schedules set out in § 112. Tampa Electric appreciates EPA's effort to create several subcategories in the proposed IB MACT rule. However, EPA should have created additional subcategories. A limited use subcategory should be created for IBs that are operated infrequently or at low capacity because of their specialized nature and use.

Response: Please refer to the preamble for discussion of the limited use subcategory.
See response to comment EPA-HQ-OAR-2002-0058-3213.1, excerpt 145 for EPA's authority to create subcategories.

Commenter Name: Chris Korleski
Commenter Affiliation: Ohio EPA
Document Control Number: EPA-HQ-OAR-2002-0058-2818.1
Comment Excerpt Number: 3

Comment: The proposal is inconsistent and, in some cases, overly-simplistic approach that relies on a few broad source categories to establish emission rates that does not recognize the variability of emissions among sources types.

Response: See response to comment EPA-HQ-OAR-2002-0058-2987.1, excerpt 3 for general requests for additional subcategories.

Commenter Name: John W. Myers
Commenter Affiliation: Tennessee Valley Authority
Document Control Number: EPA-HQ-OAR-2002-0058-2963.1
Comment Excerpt Number: 3

Comment: Units greater than 100 MMbtu/hr must install a CO monitor and demonstrate compliance on a 30-day rolling average. As explained above TVA has two limited use boilers >100 MMBtu/hr that are run infrequently. These boilers typically run only for short durations in transient mode when CO emissions would be expected to be at the higher end of a unit's emission range between startup and shutdown. Without the limited use subcategory recommended above these units would likely have to be run many additional days just to get the rolling average to be below the limit. Also without the limited use subcategory these two units would be required to have CO and oxygen monitors and would need to be run unnecessarily just to perform required emissions testing, monitor maintenance and QA checks.

Response: Please refer to the preamble for discussion of the limited use subcategory.

Commenter Name: Byron T. Burrows
Commenter Affiliation: Tampa Electric Company
Document Control Number: EPA-HQ-OAR-2002-0058-3129
Comment Excerpt Number: 3

Comment: See submittal for table listing the past five years of hours of operation for auxillary boiler.
Under the proposed rule, the natural gas-fired auxiliary boilers are subject to work practice standards requiring an annual tune up. By contrast, the proposed IB MACT rule requires oil-fired auxiliary boilers to comply with stringent emission limits and demonstrate compliance with those limits by following expensive monitoring requirements. The distinction between these two different types of auxiliary boilers is unnecessary and does not produce environmental benefits.

Response: Please refer to the preamble for discussion of the limited use subcategory.

Commenter Name: Eveleen Muehlethaler
Commenter Affiliation: Port Townsend Paper Corp
Document Control Number: EPA-HQ-OAR-2002-0058-2871.1
Comment Excerpt Number: 3

Comment: Our 1996 oil-fired boiler is an auxiliary or intermittent back-up boiler used to supplement steam supply during maintenance downs or other situations when the mill needs a little extra steam. These rules would require the installation of the same amount of multiple

pollution-control devices as our main hog fuel boiler to meet the proposed limits. Even if we can find a supplier to provide the pollution-control equipment, this cost is prohibitive. Shutting down our newest boiler will result in reduced stability of steam delivered throughout the mill, increased strain on the other steam units, constrained planned maintenance on other parts of the mill, and curtailed production.
Our oil-fired boiler is fueled by Reprocessed Fuel Oil (RFO) which is an on-spec product that was developed with Washington State to reduce the amount of petroleum-based products disposed of in landfills and storm drains.

Much like the Gas 1 category, EPA has ample justification to create a subcategory for intermittent boilers andjor boilers that run on clean liquid fuels that could be subject to work practices and other alternative approaches rather than stringent HAP limits.

Response: Please refer to the preamble for discussion of the limited use subcategory.

Commenter Name: Ted Sturdevant
Commenter Affiliation: Washington Department of Ecology
Document Control Number: EPA-HQ-OAR-2002-0058-2987.1
Comment Excerpt Number: 3

Comment: We believe that it is important for the proposed rule to set standards consistent with the Clean Air Act determination methodology. Because of the large number and variability of affected sources, more source categories than currently proposed by EPA would improve the rule and allow EPA to more successfully apply the methodology and address the differences between source types, sizes, and fuels.

Response: The EPA has created additional subcategories for limited-use units, combined grate/suspension firing units, and non-continental units. Please refer to the preamble for discussion of these new subcategories.
Section 112(d)(1) of the CAA states “the Administrator may distinguish among classes, types, and sizes of sources within a category or subcategory” in establishing emission standards. Thus, we have discretion in determining appropriate subcategories based on classes, types, and sizes of sources. We used this discretion in developing subcategories for the industrial, commercial, and institutional boilers and process heaters source category.
Through subcategorization, we are able to define subsets of similar emission sources within a source category if differences in design, processes, APCD viability, or opportunities for pollution prevention exist within the source category. We first subcategorized boilers and process heaters based on the physical state of the fuel (solid, liquid, or gaseous), which will affect the type of pollutants emitted and controls applicable, and the design and operation of the boiler, which influences the formation of fuel-based HAP emissions. We then further subcategorized boilers and process heaters based combustor design, which will affect the operation of the unit which in turn influences the formation of organic HAP emissions.

Our distinctions are based on technological differences in the equipment. The EPA contends that neither the subcategories nor MACT floor analysis was conducted considering costs, either in the proposed rule or in the final rule.

Commenter Name: Richard Rosvold
Commenter Affiliation: Xcel Energy Services, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2955.1
Comment Excerpt Number: 3

Comment: Xcel Energy supports the inclusion of a de minimis category based on hours of operation. Many boilers in this category, especially liquid-fueled boilers, are only operated for a limited number of hours each year. For such limited-use boilers, conducting annual stack tests could represent a significant portion of the unit's total operating time. It makes no sense to require extensive testing and monitoring for units that are rarely used. We suggest that units that operate for less than 500 hours per year be exempt from the monitoring and testing requirements.

Response: Please refer to the preamble for discussion of the limited use subcategory.

Commenter Name: Duane Mummert
Commenter Affiliation: South Carolina Chamber of Commerce Environmental Technical Committee
Document Control Number: EPA-HQ-OAR-2002-0058-3171
Comment Excerpt Number: 3

Comment: An additional subcategory that EPA needs to establish is one for "limited use" units. Because limited use boilers do not operate on a regular schedule and typically operate for only short periods of time, emissions profiles for these boilers can vary significantly from those of a similar boiler operating in a steady state. A capacity utilization factor of 10% was chosen for the previous boiler MACT final rule as the best means of defining a limited use unit. This definition is equally appropriate for the current rule. Also, given the limited and sporadic operation of emergency and auxiliary boilers, as well as the technical infeasibility of imposing emission limitations on these units, the limited use subcategory should require work practices in lieu of emission limits.

Response: Please refer to the preamble for discussion of the limited use subcategory.

Commenter Name: Christopher S. Colman
Commenter Affiliation: Hovensa LLC
Document Control Number: EPA-HQ-OAR-2002-0058-2863.1
Comment Excerpt Number: 3

Comment: 1. Clean Air Act
The overall approach taken by EPA appears to be that the only real design differences that merit subcategorization deal with fuel type. In other words, EPA seems to view process heaters and boilers throughout a wide range of industries as basically the same thing and the design differences between them as being insignificant and as not giving rise to differences in emissions of HAPS, taking comfort from what appears to be a broad array of data. This broad brush approach appears to be inconsistent with Section 112(c)(1) of the Clean Air Act

Section 7411 of the Clean Air Act establishes the New Source Performance Standards program. As regards boilers, Section D and subsequent amendments distinguish both on size, heat release, type of liquid fuel used and design. Importantly, for reasons that will be discussed below, NSPS Db includes separate standards for "non-continental" units. Many of these distinctions do not appear anywhere in the Boiler MACT rule. As to process heaters, they have typically been regulated on an industry by industry basis. For example, NSPS Ja regulates fuel gas combustion devices at refineries, including co-fired units.
[Footnote 4: NSPS KKKK also includes a non-continental standard]

Response: See preamble for discussion of a non-continental unit subcategory.

Commenter Name: John W. Myers
Commenter Affiliation: Tennessee Valley Authority
Document Control Number: EPA-HQ-OAR-2002-0058-2963.1
Comment Excerpt Number: 4

Comment: This same 2007 vendor proposal had a performance guarantee of 0.03 lb/MMBtu for PM when firing No. 2 fuel oil, a magnitude higher than the 0.004 lb/MMBtu being proposed. Without the limited use subcategory, meeting this proposed standard would likely require the installation of additional controls on units run very infrequently. The actual emissions reduction achieved with any such additional controls would be minimal and the cost would be substantial.

Response: Please refer to the preamble for discussion of the limited use subcategory.

Commenter Name: Caroline Choi
Commenter Affiliation: Progress Energy
Document Control Number: EPA-HQ-OAR-2002-0058-2868.1
Comment Excerpt Number: 4

Comment: Section 112(d)(1) of the CAA allows the Administrator to distinguish among "classes, types, and sizes of sources" in establishing MACT standards. In providing EPA discretion to create subcategories, § 112(d)(1) does not restrict subcategorization to cases where the "class", "type" or "size" factors affected HAP emissions. The provision merely requires EPA to establish regulations for each category or subcategory on the schedules set out in § 112. Progress Energy appreciates EPA's effort to create several subcategories in the proposed 1B MACT rule and requests that EPA create additional subcategories. A limited use subcategory should be created for industrial boilers that are operated infrequently or at low capacity because of their specialized nature and use.

For example, electric utilities operate auxiliary boilers that will be subject to the IB MACT rule because they are not steam generating units that produce electricity. Auxiliary boilers operate infrequently or in a warm standby mode and combust either natural gas or distillate fuel. As a result, the HAP emissions from the auxiliary boilers are very low and do not pose a risk to public health.
Under the proposed rule, gas-fired auxiliary boilers are subject to work practice standards requiring an annual tune up. By contrast, the proposed IB MACT rule requires oil-fired auxiliary boilers to comply with stringent emission limits and demonstrate compliance with those limits by following expensive monitoring requirements. The distinction between these two different types of auxiliary boilers is unnecessary and does not produce significant health or environmental benefits.

Progress Energy urges EPA to create a limited use subcategory for boilers combusting distillate fuel that would subject those units to the same work practice standards as gas-fired units. The limited use subcategory could have a 10% capacity factor threshold based on 10% of the maximum hourly heat input of the boiler multiplied by 8760 hours per year. Alternatively, distillate oil-fired boilers that operate in a warm standby mode at less that 10 mmBtu/hour a majority of the time could also be subject only to work practice standards.

Response: Please refer to the preamble for discussion of the limited use subcategory.

Commenter Name: Christopher S. Colman
Commenter Affiliation: Hovensa LLC
Document Control Number: EPA-HQ-OAR-2002-0058-2863.1
Comment Excerpt Number: 4

Comment: Moreover, the data presented by EPA is insufficient to reach any conclusion about differences between types of units or even as to fuel types and EPA appears to have skipped over the technical step of trying to assess legitimate design differences between units in favor of data crunching and ICR requests to find units with design characteristics that result in lower emissions, rather than looking for legitimate unit design differences and then crafting a testing program. We disagree with the "one size fits all" view and believe that significant differences do exist in the design of process heaters and boilers and that EPA policy and the Clean Air Act support subcategorization.

Heaters and boilers should be subcategorized by industry, location and even by unit type or size, because design and operating differences are relevant to emissions of HAPS from those units and such categorization and subcategorization is consistent with Section 111 and 112(c)(1) of the Clean Air Act.

Response: See response to comments EPA-HQ-OAR-2002-0058-2916, excerpt 2 and EPA-HQ-OAR-2002-0058-2702.1, excerpt 54 for subcategories based on design type, and for cyclone, firetube, and hybrid watertube-firetube boilers.

See response to comment EPA-HQ-OAR-2002-0058-2960.1, excerpt 61 for additional subcategory based on regional fuel availability or geographic location.

See response to comment EPA-HQ-OAR-2002-0058-2818.1, excerpt 18 for subcategorizing according to heat input size.

See response to comment EPA-HQ-OAR-2002-0058-2795.1, excerpt 1 for additional subcategory for small municipal utilities or subcategorizing according to sector.

Commenter Name: Gordon M. Smith
Commenter Affiliation: Mitsubishi Polyester Film, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2912
Comment Excerpt Number: 4

Comment: EPA's September 13, 2004 rule included a "limited-use" subcategory for units with average capacity factors of 10% or less, however the proposed rule does not continue that approach. Instead, it presumes that limited use units are just like those operated full-time which burn a similar fuel.
Limited use sources operate intermittently and for shorter periods of time (e.g., small package boilers that are only used during mill outages, a backup boiler that runs when other units are being fixed, or a peaking unit used to supplement electric generation during particularly hot summer days). Compared to most boilers, these units spend a far greater percentage of their time starting up and shutting down. As a result, their emissions profiles differ from sources which operate in efficient steady-state manners. For example, they are likely to experience higher CO levels as the boiler heats up due to incomplete combustion. Similarly, many pollution control technologies are either difficult to use or ineffective during startup and shutdown periods and would be cost prohibitive to install and use for only short periods of time during a year. These are just the sort of "class" and "type" distinctions which merit consideration for subcategorization under §112(d)(2).

A capacity utilization factor of 10% was chosen for the previous boiler MACT final rule as the best means of defining a limited use unit (69 FR at 55223). This definition is equally appropriate for the current rule. Given the limited and sporadic operation of emergency and backup boilers, as well as the technical infeasibility of imposing emission limitations on these units, the limited use subcategory should require work practices in lieu of emission limits.

Response: Please refer to the preamble for discussion of the limited use subcategory.

Commenter Name: Robert R. Perry
Commenter Affiliation: FirstEnergy Generation Corp
Document Control Number: EPA-HQ-OAR-2002-0058-2772.1
Comment Excerpt Number: 4

Comment: EPA should add a subcategory for ICI Boilers with capacity factors less than 10 percent.
FGCO has a number of liquid fired (No. 2 fuel oil) ICI boilers with rated heat inputs greater than 10 mmBtu/hr subjecting them to the proposed ICI Boiler MACT limits. These industrial-sized boilers are used very infrequently to provide a source of steam to power steam driven auxiliaries for much larger electric generating units (EGU) during the start-up process. When the EGU achieves steady-state operation (which is typically a matter of hours), the steam supply is switched over from the auxiliary boiler to the EGU, and the auxiliary boiler is shut down.

None of these auxiliary boilers has operated more than 10 percent of the time on an annual basis and in most cases they operate much less than 5 percent. Some units are even limited by Title V requirements to less than 5 percent annual operation. To impose these ICI Boiler emission limits on limited use boilers is unnecessary, exceedingly costly, provides very nominal environmental benefit at best, and may even result in less efficient power plant operation and more emissions for the following reasons.

First, these auxiliary boilers are generally used to power steam-driven auxiliary equipment for overall system efficiency purposes. (It is more efficient to use steam-driven auxiliaries than electric motors because you eliminate the efficiency losses associated with converting the energy in the steam to electricity and then powering an electric motor to drive the pump or fan.) This improves the overall efficiency of the EGU and results in less overall emissions per unit of output. The imposition of extremely stringent ICI Boiler emission limits on these limited use auxiliary ICI boilers may force the power plant to retire the auxiliary boiler and convert the steam driven auxiliary equipment to electric motors. Likewise, where these auxiliary boilers are utilized to augment plant heating when the larger EGU is shut down, the facility may elect to install less efficient electric heating, since the power supply is readily available. In effect, EPA may force the shutdown auxiliary boilers and reduce the efficiency of power plant operation.

Second, operation of these limited use auxiliary boilers at a power plant occurs at largely random intervals associated most frequently with unplanned outages and startups of larger EGUs. As such, it may be impossible to predict when the auxiliary boiler will be in operation and the unit may have to be artificially scheduled to operate to conduct periodic compliance demonstrations or calibrate monitoring equipment. Starting up one of these auxiliary boilers, consuming fuel and producing emissions just to demonstrate compliance will likely also increase overall emissions from the facility and is counterproductive and a poor use of resources.

Third, starting the auxiliary boiler to demonstrate compliance when the larger EGU is operating leaves the auxiliary boiler with no place to send its steam for meaningful use and benefit. In most instances, the auxiliary boiler will be forced to vent its steam to the atmosphere for the duration of the compliance demonstration or calibration. This would be an absolute waste of fuel and the auxiliary boiler would be creating emissions for the sole purpose of demonstrating compliance. In certain instances, the auxiliary boiler may not even have a means to vent the steam to the atmosphere since this mode of operation is so counterintuitive and may have never been contemplated.

These counterintuitive, unintended consequences argue against applying stringent ICI Boiler MACT limits on infrequently used auxiliary boilers at an EGU. Accordingly, EPA should add a subcategory for ICI Boilers located at EGUs with capacity factors less than 10 percent to avoid increased emissions and reduced efficiency from both the EGU and their auxiliary boilers.

Response: Please refer to the preamble for discussion of the limited use subcategory.

Commenter Name: Tim Hagley
Commenter Affiliation: Minnesota Power
Document Control Number: EPA-HQ-OAR-2002-0058-2829.1
Comment Excerpt Number: 5

Comment: Work Practice Standards Should Apply to Limited Use and Small Boilers. MP commends EPA's decision to apply work practice standards to gas-fired boilers. These work practice standards should be expanded to oil-fired limited-use and small boilers, such as utility auxiliary boilers. HAP emissions from limited-use and small boilers firing distillate fuel are exceedingly low and do not pose a risk to public health. Applying stringent emission limits to these boilers could result in expensive compliance costs with no meaningful environmental benefits. Since these emissions would be low, EPA should create a separate subcategory for these limited-use boilers, and apply the same work practice standards currently proposed for gas-fired boilers.

Response: Please refer to the preamble for discussion of the limited use subcategory.

Commenter Name: Ted Sturdevant
Commenter Affiliation: Washington Department of Ecology
Document Control Number: EPA-HQ-OAR-2002-0058-2987.1
Comment Excerpt Number: 5

Comment: The NESHAP should appropriately class and assess types of boilers and the fuels they use when setting standards and emission limits.

The proposed rule should acknowledge the diversity and variability of top performing boilers across sectors of the economy, including differences in function, load, fuel mix and pollution control efficiencies when setting emission standards.

EPA should consider segregating boilers by size. Segregating boilers by size consistent with the size ranges in the NSPS rules for boilers (Subparts D, Db, and Dc) may be a reasonable approach.

Response: See response to comment EPA-HQ-OAR-2002-0058-2798.1, excerpt 9 for subcategorizing according to NSPS rule's heat input size structure.

Commenter Name: Kathryn M. Cunningham
Commenter Affiliation: Consumers Energy Company
Document Control Number: EPA-HQ-OAR-2002-0058-2904.1
Comment Excerpt Number: 5

Comment: Consumers operates a number of its boilers/heaters on a limited basis due to cold weather conditions. For example, one of the distillate oil fired boilers that contributed to the ICR Part II, operates at a capacity of less than 10%. When it does operate, it is at variable load ranges, depending on ambient temperature. It is used to heat a molten sulfur storage tank and also for building heat. The ICR testing was not done at variable load ranges and thus did not capture actual emissions that the boiler may typically emit. Due to the limited use of this boiler, it is impossible to meet the emission limits as proposed - even on a 30 day rolling average,. Consumers is advocating for an exemption from the emission limits for boilers with limited use — less than 10% capacity. Consumers believes the work practice standard should apply to these boilers instead of the emission limits.

Response: Please refer to the preamble for discussion of the limited use subcategory.

Commenter Name: Bill Wemhoff
Commenter Affiliation: National Rural Electric Cooperative Association
Document Control Number: EPA-HQ-OAR-2002-0058-2835.1
Comment Excerpt Number: 7

Comment: Section 112(d)(1) of the CAA allows the Administrator to distinguish among "classes, types, and sizes of sources" in establishing MACT standards. This subcategorization language mirrors earlier language found in CAA § 111. In providing EPA discretion to create subcategories, § 112(d)(1) does not restrict subcategorization to cases where the "class," "type" or "size" factors affect HAP emissions. The provision merely requires EPA to establish regulations for each category or subcategory on the schedules set out in § 112. Indeed, EPA has not previously subcategorized under § 111 based solely on emission effects. For example, under § 111 EPA has subcategorized boilers on the basis of size (heat input) or the type of fuel burned (coal, oil or gas). These subcategorization decisions were based on feasibility and/or cost considerations, not on the level of emissions.

Response: See response to comment EPA-HQ-OAR-2002-0058-3213.1, excerpt 145 for EPA's authority to create subcategories.

See response to comment EPA-HQ-OAR-2002-0058-2987.1, excerpt 3 for basis of subcategorization.

Commenter Name: Eveleen Muehlethaler
Commenter Affiliation: Port Townsend Paper Corp
Document Control Number: EPA-HQ-OAR-2002-0058-2871.1
Comment Excerpt Number: 8

Comment: We recommend that EPA reconsider the Boiler rule to include assignment of more limited-use subcategories for boilers such as ours.

Response: Please refer to the preamble for discussion of the limited use subcategory.

Commenter Name: Bill Wemhoff
Commenter Affiliation: National Rural Electric Cooperative Association
Document Control Number: EPA-HQ-OAR-2002-0058-2835.1
Comment Excerpt Number: 9

Comment: A limited use subcategory should be created for IBs that are operated infrequently because of their specialized nature and use.

Response: Please refer to the preamble for discussion of the limited use subcategory.

Commenter Name: Sheila C. Holman
Commenter Affiliation: North Carolina Department of Environment and Natural Resources
Document Control Number: EPA-HQ-OAR-2002-0058-2798.1
Comment Excerpt Number: 9

Comment: In the proposed rule, the only sub-categorization based on heat input size is a 10 MM Btu/hr threshold. The proposed MACT for existing sources greater than 10 MM Btu/hr includes add-on control devices such as scrubbers, ESPs, sorbent injections systems, etc., which have significant capital and operating costs. The cost and cost-effectiveness (dollars per emission amount reduced) is highly dependent on heat input size, and larger combustion sources are more highly controlled than smaller sources. This fact is manifested by EPA's New Source Performance Standards Subpart Dc for Industrial Boilers. While it may be technically-feasible to install a wet scrubber on a 250 MM Btu/hr coal fired-boiler, the cost of such control on a 15 MM Btu/hr boiler is not economically feasible for most facilities. To avoid forcing small units to retrofit add-on controls that have not been demonstrated to be cost effective, NC DAQ recommends using a similar heat input size structure with progressively more stringent standards as in 40 CFR. 60, Subpart Dc: (1) less than 30, (2) 30100, (3) greater than 100, (with all categories in units of MM Btu/hr, but raising the threshold from 10 to 30 MM Btu/hr as suggested above).

EPA should further subcategorize the MACT standards based on heat input size for solid fuel fired boilers and heaters. In order to evaluate and help justify further sub-categorization, EPA should:

Size-segregate the source populations,

Rank HAP emissions by sources for each size category

Identify the emission control technologies in each category,

Characterize the extent of existing emission controls in each category,

Estimate the cost-effectiveness of adding emission controls for each category.

Rank each category's control cost-effectiveness for each HAP.

Response: See response to comment EPA-HQ-OAR-2002-0058-2818.1, excerpt 18 for subcategorizing according to heat input size.

Commenter Name: Christopher S. Colman
Commenter Affiliation: Hovensa LLC
Document Control Number: EPA-HQ-OAR-2002-0058-2863.1
Comment Excerpt Number: 10

Comment: Process Heaters in the refining industry (and in other industries as well) must be designed for the process that they support. One key variable is temperature, which can vary in different processes by 600 or more degrees because of the heat needed for a particular type of process. For example, a delayed coking unit operates at relatively high temperatures to thermally crack heavy residuals into lighter products. Conversely, a Platformer (Catalytic Reforming) uses a very unusual heater design tailored to the catalytic reforming process and also incorporates smaller heaters between reactors. Design differences in process heaters to support the functions of different units lead to differences in residence time and temperature. Another design difference that changes CO emissions is whether air preheat is used. Air preheat improves energy efficiency, but raises NOx emissions. The NOx/CO tradeoff is well known in literature:

For these reason, it is likely that many (if not all) of the boilers in the database used to set the CO floor (e.g. DAK9) are not controlled for NOx and use standard burner designs. Similarly, higher excess oxygen levels reduce CO but increase energy usage, increasing CO_2 emissions, working directly contrary to a provision in the Boiler MACT intending to improve energy efficiency. [Footnote 9: Confirmed orally with persons knowledgeable about the DAK facility.]

Response: See response to comment EPA-HQ-OAR-2002-0058-2912, excerpt 2 for separate subcategories for process heaters and boilers.
See response to comment EPA-HQ-OAR-2002-0059-2702.1, excerpt 68 for additional subcategory to distinguish between units with low NOx burners.

Commenter Name: Roy W. Wood
Commenter Affiliation: Eastman Kodak Company
Document Control Number: EPA-HQ-OAR-2002-0058-2917.1
Comment Excerpt Number: 12

Comment: Kodak urges EPA to create a "limited use" category for existing fuel oil-fired auxiliary boilers that requires a work practice standard in lieu of an emission standard. Many auxiliary boilers at industrial facilities are greater than 10 million Btu/hour and burn fuel oil, but operate for only limited time periods to provide steam and/or electricity when a primary boiler unit is not operational. Kodak's Eastman Business Park site in Rochester, New York has four such units which are only operated when one of the larger coal fired units is off-line. Since they are frequently not needed for months at a time, they are also fired for short periods on a monthly basis to maintain operational readiness. Auxiliary boilers typically operate less than 10% of their annual capacity factor (less than 870 hours per year). Requiring a work practice standard (similar to that allowed for existing natural gas boilers) would effectively reduce emissions of HAP for this category of boilers. Expensive boiler modifications to switch fuel to natural gas or to meet emission standards will not result in significant HAP reductions. For these reasons Kodak urges EPA to create a "limited use" category that applies a work practice standard in lieu of an emission standard for fuel oil-fired auxiliary boilers located at major sources of HAP. This category would apply only where these sources are limited to 870 hours per year as a federally enforceable permit condition.

Response: Please refer to the preamble for discussion of the limited use subcategory.

Commenter Name: Christopher S. Colman
Commenter Affiliation: Hovensa LLC
Document Control Number: EPA-HQ-OAR-2002-0058-2863.1
Comment Excerpt Number: 14

Comment: For purposes of CO emissions, boilers fall into two major types—field erected and package boilers. Package boilers are smaller and are size limited so that they can be shipped and installed on site. Package boilers are particularly important to island based facilities such as HOVENSA because they can be shipped to islands and installed without as much construction, which is a much higher cost in the Virgin Islands as will be discussed below. As these boilers reach their maximum size (~250 mmbtu/hr), the firebox becomes constrained causing CO to increase at higher loads. Larger boiler designs may also have a vertical air flow regime which allows for the incorporation of flue combustion or overfire air, which have the effect of lowering NOx and CO. As is the case with many NSPS rules, we recommend that boilers be subcategorized by size. Boilers at refineries, particularly those without natural gas, may be expected to have higher load variability as is the case with process heaters.

Response: See response to comment EPA-HQ-OAR-2002-0058-2818.1, excerpt 18 for subcategorizing according to heat input size.

Commenter Name: Wayne J. Galler and Deborah A. Phillips
Commenter Affiliation: Georgia Industry Environmental Coalition, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2882.1
Comment Excerpt Number: 15

Comment: GIEC suggests that EPA develop a separate subcategory for "limited use" boilers with no numerical emission limits. In the 2004 Boiler MACT Rule, EPA treated boilers that operated with average capacity factors of 10% or less separately from all other boilers. Many industrial operations utilize "limited use boilers for cold startups and intermittently for short periods of time such as for facility outages, or as a backup boiler that runs when other units are being repaired, or a peaking unit used to supplement electric generation during particularly hot summer days_ Compared to most boilers, these units spend a far greater percentage of their time starting up and shutting down. As a result, their emissions profiles differ from sources which operate in efficient steady-state manners_ For example, they are likely to experience higher CO levels as the boiler heats up due to incomplete combustion. Similarly, many pollution control technologies are either difficult to use or ineffective during startup and shutdown periods and would be cost prohibitive to install and use for only short periods of time during a year These are just the sort of "class" and "type" distinctions which merit consideration for subcategorization under Section 112(d)(2) of the Act.

EPA provided a separate category for emergency use engines under the. RICE MACT (40 CFR 63 Subpart ZZ77-March 3, 2010) with work practice standards in lieu of numerical emission limits. GIEC believes EPA should follow a similar path for "limited use" boilers under the final Boiler MACT Rule.

Response: Please refer to the preamble for discussion of the limited use subcategory.

Commenter Name: Christopher S. Colman
Commenter Affiliation: Hovensa LLC
Document Control Number: EPA-HQ-OAR-2002-0058-2863.1
Comment Excerpt Number: 17

Comment: Because design and operating differences are relevant to emissions of HAPS from refinery process heaters, particularly as regards CO and steady state operations, they should be separately subcategorized. This approach is exactly that used by EPA in proposing a separate work practice for metal finishing furnaces:

"These individual burners are operated to cycle on and off to maintain the proper temperatures throughout the various zones of the process heater. Thus, due to their design, these process heaters rarely operate in a steady-state condition due to burners constantly starting up and shutting down. This results in emissions characteristics different from the process heaters used in other industries."

Our comment is also consistent with input from SERs. ("SERs commented that EPA should subcategorize based on fuel type, boiler type, duty cycle, and location")

Response: See response to comment EPA-HQ-OAR-2002-0058-2912, excerpt 2 for separate subcategories for process heaters and boilers.

Commenter Name: Richard L. Killion
Commenter Affiliation: Babcock and Wilcox Power Generation Group
Document Control Number: EPA-HQ-OAR-2002-0058-2722.1
Comment Excerpt Number: 17

Comment: MACT emission limit subcategories for existing equipment should take into consideration the existing combustion technologies of the existing equipment.

However, new equipment should be subdivided by fuel type only. Having limits on new units subdivided into combustion technology precludes the development of new technologies that may not exist today, and could inadvertently encourage technologies that allow higher emissions.

Response: Subcategories were developed to consider design and operating conditions of various types of boilers and process heaters. Although combustor design varies, many of the designs are related to the type of fuels combusted at the units and were not selected to promote ineffficient technologies. See the preamble for how EPA allowed units to switch subcategories. EPA determined that combustor-designed based subcatetoreis are appropriate.

Commenter Name: Lee B. Zeugin
Commenter Affiliation: Utility Air Regulatory Group
Document Control Number: EPA-HQ-OAR-2002-0058-2880.1
Comment Excerpt Number: 18

Comment: Electric utilities that operate auxiliary boilers will be subject to the IB MACT rule because they are not steam generating units that produce electricity. Auxiliary boilers operate infrequently normally during plant startups and combust either natural gas or distillate fuel. As a result, the HAP emissions from the auxiliary boilers are exceedingly low and do not pose any risk to public health.

Under the proposed rule, gas-fired auxiliary boilers are subject to work practice standards requiring an annual tune-up. By contrast, the proposed IB MACT rule requires oil-fired auxiliary boilers to comply with stringent emission limits and demonstrate compliance with those limits by following expensive monitoring requirements. The distinction between these two different types of auxiliary boilers is unnecessary and does not produce environmental benefits.

EPA should create a limited use subcategory for boilers combusting distillate fuel that would subject those units to the same work practice standards as gas-fired units. The limited use subcategory should have a 10% capacity factor threshold. Eligibility for this subcategory would be determined based on 10% of the maximum hourly heat input of the boiler multiplied by 8760 hours per year.

Response: Please refer to the preamble for discussion of the limited use subcategory.

Commenter Name: Chris Korleski
Commenter Affiliation: Ohio EPA
Document Control Number: EPA-HQ-OAR-2002-0058-2818.1
Comment Excerpt Number: 18

Comment: The proposed rule defines a single emission limit applicable by boiler type over a very broad capacity range of either greater or less than 10 mmBTU/hr. It has been our experience that there are distinct combustion characteristics for the same type of boiler at additional capacity thresholds that may affect the emissions of organic HAP emissions (refer to discussion on carbon monoxide emission limit). For example, liquid fuel-fired boilers in the range of 100 to 150 mmBTU/hr or larger are multiple burner systems, whereas smaller boilers are typically single burner systems. In similar fashion, differences in combustion configuration are expected for process heaters through different size ranges and by types of application. Another example is coal-fired stoker boilers which in range in size from 50 mmBTU/hr to over 500 mmBTU/hr. This difference in stoker boiler size greatly affects the characteristics of combustion, the rate of heat absorption, boiler residence time, etc., all of which affect combustion characteristics of the sources. Clear distinctions in combustion characteristics for different types of boilers are identified in EPA's documents of Achievable Control Technology for NOx controls. The same concept should apply to the MACT standards.

Response: The EPA sees no legal justification establishing a separate subcategory based on the size of the unit. In the final rule EPA did not develop a separate subcategory for small boilers but instead identified that units less than 10 mmBtu/hr qualify for a work practice under Section 112(h) of the CAA. See the preamble for further discussion of how the threshold of 10 mmBtu/hr was selected for the work practice standard.

The EPA does not see justification for creating a separate subcategory for medium sized units. The EPA does not view medium sized boilers as being different than larger boilers. Combustor designs, applicable air pollution control devices, fuels used, and operation are similar for large and medium units. While actual pollution controls used and monitoring equipment may be different, the CAA does not allow EPA to subcategorize on these parameters.

Commenter Name: Chris Korleski
Commenter Affiliation: Ohio EPA
Document Control Number: EPA-HQ-OAR-2002-0058-2818.1
Comment Excerpt Number: 21

Comment: It may be necessary to address combustion equipment configurations though separate source categories. Ohio EPA recommends evaluating sources with and without NOx combustion modifications in order to delineate the potential interaction with NOx emission requirements.

Response: See response to comment EPA-HQ-OAR-2002-0059-2702.1, excerpt 68 for additional subcategory to distinguish between units with low NOx burners.

Commenter Name: Robert Thornton
Commenter Affiliation: International District Energy Association
Document Control Number: EPA-HQ-OAR-2002-0058-2918.1
Comment Excerpt Number: 21

Comment: Within the universe of potentially affected units, many are operated as stand-by or redundant capacity, reserved for use during periods when circumstances mandate the need to provide steam in order to preserve conditions within the distribution system. These boilers are often equipped with coils to maintain internal metal temperatures, as well as boiler drum pressure and temperature, to allow for quick response following the combustion safety purge.

IDEA recommends that EPA provide for these sorts of operating scenarios in the final rule by establishing a limited use subcategory for liquid or gas 2 units based on 10% annual capacity factor or 1,000 hours/year as a threshold. These units operate for short periods of time during the year and as such may experience relatively little SSM. The short run times would likely exacerbate the effect of startup/shutdown on 30 day averages. Because limited use units do not operate regularly, their emissions differ from average boilers operating for longer periods of time or near their design capacity.

EPA has recognized that "units operate most efficiently when operated at or near their design capacity." 75 FR 32023-24. Based on their operating schedule, limited use units may or may not operate at or near their design capacity, but if they do it is for limited periods of time. Considering this, limited use units may operate for a greater percentage of their total operating time inefficiently as compared to steady state units operating near design capacity.

In addition, the short operating times of limited use units results in difficulties in effectively controlling emissions. As EPA noted in a 2004 response to comments document, based on the operating schedules of limited use units the agency could not identify a control technology for controlling organic HAP emissions. See EPA, Response to Public Comments on Proposed Industrial, Commercial, and Institutional Boilers and Process Heaters NESHAP, at 67 (Feb. 25, 2004). Considering these differences based on the operating schedule of limited use units, EPA should establish a subcategory for limited use boilers and process heaters. The subcategory should be defined to include units with a capacity utilization factor of 10 percent; or, by a 1,000 hours operating per year threshold.

Response: Please refer to the preamble for discussion of the limited use subcategory.

Commenter Name: Christopher S. Colman
Commenter Affiliation: Hovensa LLC
Document Control Number: EPA-HQ-OAR-2002-0058-2863.1
Comment Excerpt Number: 23

Comment: 1. General
HOVENSA, as an island based refinery, has unique configurations and constraints that mainland refineries do not. One of the key constraints is that HOVENSA cannot physically access natural gas pipelines. This makes the burning of liquid fuels (produced on site) an unavoidable part of doing business in St. Croix, as EPA observes in the rule preamble. There are many other constraints, either deriving from oil burning or remote location that affect the design, configuration and operation of heaters and boilers at HOVENSA and other non-continental refineries, such that their unique characteristics merit a specific subcategory. Moreover, the dual fired heaters used at HOVENSA are a very different design than EPA apparently contemplated in establishing subcategories and this design also affects the combustion chamber design. We urge EPA to adopt a remote /island location subcategory, as it did in the CISWI rule for smaller remote facilities, because of these inherent design and operating constraints.

Response: See preamble for discussion of a non-continental unit subcategory.

Commenter Name: Sarah E. Amick
Commenter Affiliation: Rubber Manufacturers Association
Document Control Number: EPA-HQ-OAR-2002-0058-2941.1
Comment Excerpt Number: 24

Comment: CAA §112(c)(1) instructs EPA to establish “categories and subcategories” of sources for regulation under Section 112. CAA §112(d)(1) then further provides that EPA “may distinguish among classes, types and sizes of sources within a category or subcategory” when establishing MACT standards. These provisions vest EPA with the clear authority to group like units for purposes of establishing emissions limitations. EPA's subcategorization decisions, however, must turn on legitimate "class" "type" or size" distinctions as required by §112(d).

The legislative history explains what Congress meant when it authorized EPA to distinguish among sources by "class" "type" or "size." The relevant Senate Report indicates that EPA should: [T]ake into account factors such as industrial or commercial category, facility size, type of process and other characteristics of sources which are likely to affect the feasibility and effectiveness of air pollution control technology. Cost and feasibility are factors which may be considered by the Administrator when establishing an emission limitation for a category under Section 112 . . . where a group of sources may share the characteristics of other sources in the category, the Administrator may establish subcategories for such sources. S. REP. NO. 228, 101st Cong., 1st Sess. 166 [JA 1426] (emphasis added).

That language has two key implications. First, it confirms that Congress' use of the broad concepts of "class" "type" or "size" was meant to allow subcategorization based on (and require consideration of) a broad array of factors. That is particularly true given Congress' open-ended statement that EPA should consider "other characteristics of sources" when grouping them for purposes of establishing emissions limits. Second, this statement confirms that, while cost issues alone may not be sufficient to require subcategorization, costs are relevant to subcategorization decisions. See also, Id. (indicating that subcategorization "wholly on economic grounds" is inappropriate) (emphasis added). By clarifying that individual facilities may not be granted categorical waivers "based on assertions of extraordinary economic effect," id., the Senate Report confirms that the threat of severe economic consequences on a subgroup sharing other common attributes supports subcategorization.[A related House Report confirms that cost implications are relevant to all facets of MACT regulation by providing that "MACT is not intended to require unsafe control measures, or to drive sources to the brink of shutdown." HOUSE REP. NO. 101-490, Part 1, at 328. Preliminary of control technology, (2) effectiveness of control technology, and (3) costs of control. Where those factors are present, subcategorization is warranted.] Thus, §112(d)(2) authorizes (and requires) EPA to consider differences in "commercial category, facility size, type of process and other characteristics" that may affect: (1) feasibility of control technology, (2) effectiveness of control technology, and (3) costs of control. Where those factors are present, subcategorization is warranted.

Response: See response to comment EPA-HQ-OAR-2002-0058-3213.1, excerpt 145 for EPA's authority to create subcategories.

Commenter Name: Chris Korleski
Commenter Affiliation: Ohio EPA
Document Control Number: EPA-HQ-OAR-2002-0058-2818.1
Comment Excerpt Number: 24

Comment: The proposed NESHAP rule does not appear to address or set standard for several specific cases:

-Cyclone boilers
-Petroleum coke fuel fired boilers
-Natural gas fired boilers fired by landfill gas
-Propane fired boilers
-Gasification process fired boilers
-Process heating where the heated materials contribute to the pollutants

Response: See response to comments EPA-HQ-OAR-2002-0058-2916, excerpt 2 and EPA-HQ-OAR-2002-0058-2702.1, excerpt 54 for subcategories based on design type, and for cyclone, firetube, and hybrid watertube-firetube boilers.
See response to comments EPA-HQ-OAR-2002-0058-2761.1, excerpt 15 and EPA-HQ-OAR-2002-0058-2702.1, excerpt 73 for the definition of natural gas needs to be broader to account for non-geological origins of natural gas.
See response to comment EPA-HQ-OAR-2002-0058-2849.1, excerpt 12 for Gas 1 subcategory and propane fired boilers.

Commenter Name: Christopher S. Colman
Commenter Affiliation: Hovensa LLC
Document Control Number: EPA-HQ-OAR-2002-0058-2863.1
Comment Excerpt Number: 24

Comment: 2. No Natural Gas-Oil Burning Required

The primary fuel burned at HOVENSA, as noted above, is the gas produced by the different process units. Because there is no natural gas pipeline, HOVENSA has no choice but to burn liquid fuels to maintain a fuel/heat balance. HOVENSA has no outlet or storage for the hydrocarbon gas it generates and so this fuel gas must be burned in onsite combustion units. A refinery will burn all of the fuel gas it produces, but by design, the fuel gas produced at a refinery is less than the energy required to operate the refinery, otherwise the refinery would be required to flare the fuel gas.
The characteristic that HOVENSA and other remote oil burning refineries share is that they do not have a natural gas supply, which is functionally equivalent to refinery fuel gas from an operational and heater/boiler design perspective. The result is that HOVENSA must supplement the fuel gas with residual or distillate fuel oil. Because of their very different characteristics, fuel oils cannot be combusted in the same burner elements as gas fuels. They can be simultaneously combusted in a burner equipped with both oil and gas burner elements, which changes combustion dynamics and is an operating mode not apparently recognized by EPA as discussed below. The inability to obtain natural gas removes the option of being able to burn only gaseous fuels as a compliance strategy and burning fuel oil as a supplemental fuel makes complying with this proposed MACT unfairly onerous for HOVENSA and similarly situated major facilities.

Response: See preamble for discussion of a non-continental unit subcategory.

Commenter Name: Sarah E. Amick
Commenter Affiliation: Rubber Manufacturers Association
Document Control Number: EPA-HQ-OAR-2002-0058-2941.1
Comment Excerpt Number: 26

Comment: Currently, the proposed rule does not have a subcategory for backup or emergency use boilers. These boilers do not operate on a regular schedule and typically operate for only short periods of time. As a result, emissions profiles for these boilers can vary significantly from those of a similar boiler operating in a steady state. See id. at 32,023 ("Combustion units operate most efficiently when operated at or near their design capacity. The combustion efficiency tends to decrease as the unit's load (steam production) decreases."). Given their short run times, there are also technological limitations on how effectively emissions from these units can be controlled, particularly for organic HAP emissions. See Response to Public Comments on Proposed Industrial, Commercial, and Institutional Boilers and Process Heaters NESHAP at 67 (February 25, 2004) ("[W]e could not identify any control technologies that would reduce organic HAP emissions [for limited use boilers]. Therefore, while larger units may emit more than smaller units, we have not identified any appropriate technology or method that could be used to reduce organic HAP emissions."). Finally, since "limited use boilers, when called upon to operate, must respond without failure and without lengthy periods of startup,"[24 National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters; Final Rule, 69 Fed.Reg. 55,218, 55,232 (September 13, 2004).] a significantly larger percentage of their annual operation is be devoted to maintenance and readiness testing than other commercial, industrial, or institutional boilers. These differences justify the creation of a limited use category for emergency and backup boilers.

Response: Please refer to the preamble for discussion of the limited use subcategory.

Commenter Name: Sarah E. Amick
Commenter Affiliation: Rubber Manufacturers Association
Document Control Number: EPA-HQ-OAR-2002-0058-2941.1
Comment Excerpt Number: 27

Comment: The previous version of EPA's boiler MACT recognized that boilers used for emergencies or as backup boilers should be placed in a subcategory due to the limited and unscheduled nature of their use. See National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters; Final Rule, 69 Fed.Reg. 55218, 55232 (September 13, 2004). EPA recognized that "[t]he boiler database indicates that these infrequently operated units typically operate 10 percent of the year or less," however, "[t]hese limited use boilers, when called upon to operate, must respond without failure and without lengthy periods of startup." Id.[25 This number was calculated using the prior database. For completeness of the administrative record, therefore, we would request that this database be made part of the current docket.] Continued recognition of this subcategory is both supported by recent EPA action and practically justified.

Response: Please refer to the preamble for discussion of the limited use subcategory.

Commenter Name: Sarah E. Amick
Commenter Affiliation: Rubber Manufacturers Association
Document Control Number: EPA-HQ-OAR-2002-0058-2941.1
Comment Excerpt Number: 30

Comment: The Limited Use Subcategory Should be Based on a Capacity Utilization of 10%. For CI RICE, "[t]here is no time limit on the use of emergency stationary engines in emergency situations." Id. at 9654. This is a reasonable provision, since an emergency RICE must continue to operate as long as an emergency persists. This provision should similarly apply to limited use boilers. In addition, however, EPA recognized in the final CI RICE MACT rule that these units also need to operate in other, non-emergency situations, including for maintenance and participation in demand response programs. As a result, EPA allocated time within each operating year (100 hours) for emergency CI RICE to operate in non-emergency situations for what EPA referred to as "maintenance checks and readiness testing." Id. at 9654. In addition, EPA allocated 50 hours of each unit's maintenance and readiness time for other non-emergency uses, including at least 35 hours for non-financial uses and up to 15 hours for participation in emergency demand response programs, where the unit would be needed to provide power to a "regional transmission organization or equivalent balancing authority" and the "transmission operator has determined there are emergency conditions that could lead to a potential electrical blackout." Id. Examples of such conditions were also provided by EPA, including "unusually low frequency, equipment overload, capacity or energy deficiency, or unacceptable voltage level." Id.
Given the importance of demand response programs to averting blackouts and other emergencies, the State of Ohio recently went even further, expanding the definition of "emergency" in its permit-by-rule exemptions from MACT for emergency generators less than 50 horsepower to include:Conditions where a regional transmission organization notifies electric distributors that an emergency exists or may occur and it is necessary to implement emergency procedures for voluntary load curtailments by customers within Ohio, in response to unusually low frequency, equipment overload, capacity or energy deficiency, unacceptable voltage levels, or other emergency conditions leading to a potential electrical blackout. . . . Proposed Amendment to OAC 3745-31-03 (June 7, 2010); Executive Order 2010-07S (June 7, 2010) (adopting proposed amendment).

As stated by Governor Strickland, "[i]n the event of an electrical grid failure that could result in widespread electrical blackouts, Emergency Load Response Programs allow emergency generator operators to temporarily utilize their generators without the need to obtain a permit to help prevent those blackouts. Allowing the use of emergency generators in such circumstances protects public health and welfare." Executive Order 2010-07S at ¶4. Further, Ohio has exempted all emergency electrical generators operating less than 500 hours per rolling 12-month period from obtaining a permit to install. See Proposed Amendment to OAC 3745-31-03.

For these same reasons, EPA should consider both the necessity of maintenance and readiness testing, as well as participation in emergency demand response programs and other "non-emergency" uses in setting the parameters for a limited use subcategory. While limits based on hours of operation like those used in the CI RICE MACT are one option, another and potentially easier standard to administer would be to rely on capacity utilization. Boilers, unlike RICE, cannot start up or shut down quickly, making it difficult for boiler operators to run a boiler for only a set number of hours. An hours-of-operation limit, therefore, would be less practical than a limit based on capacity utilization. Moreover, as EPA noted in the Proposed Rule, some emissions from boilers are not dependent on operating parameters such as hours operated, but rather on the fuel consumed. See National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines, 75 Fed.Reg. at 32017 (discussing fuel-dependent HAP). A capacity utilization factor of 10% was chosen for the previous boiler MACT final rule as the best means of defining a limited use unit. See National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters; Final Rule, 69 Fed.Reg. at 55223. This definition is equally appropriate for the current rule.

Response: Please refer to the preamble for discussion of the limited use subcategory.

Commenter Name: Christopher S. Colman
Commenter Affiliation: Hovensa LLC
Document Control Number: EPA-HQ-OAR-2002-0058-2863.1
Comment Excerpt Number: 32

Comment: 6. Fuel Availability
HOVENSA has only one practical supplier of fuel oil, which is the refinery itself. The HAP metals content of the fuels particularly for residual fuel oil, is a direct result of the crude slate used at HOVENSA. That is because residual fuel oil (except for slurry oil, production of which is discussed above) is typically the bottom fractions from either atmospheric crude distillation units, vacuum units or visbreakers. These bottom fractions have high boiling points and, except for mercury, metals in the crude oil will tend to stay with these fractions. At HOVENSA, residual fuel used in heaters and boilers, which must be low sulfur residual fuel oil (<1% S, and expected to be required to be <.5% in the future, eliminating use of low metals slurry oil), is primarily produced in Crude and Vacuum units on the west side of the HOVENSA refinery from relatively low sulfur crude. However, other units (including those used to process heavy sour crudes) may contribute to the residual oil blending pool, which may contribute blending components that are higher in metals. 31
HOVENSA processes a large number of crude types as compared to state-side refineries because of its island location:

There is no crude supply pipeline to St. Croix/HOVENSA. Many mid-continent refineries are tied to production from a specific area and see fewer crude types.

All crude is supplied by ship and the physical size of crude ships is limited by what is available in the world and manageable by load/discharge ports

Unless located in close geographic location to the Caribbean, the crude ship travel time can be longer than the refinery processing time for the amount of crude on a ship

The physical collection rate of the specific crude out of the ground can be less than the actual processing rate at HOVENSA

The commercial availability of specific crude types in the world in the quantities necessary for HOVENSA

The metals content varies substantially between different crude oils that are presently being used at the refinery to produce residual fuel oil. (See submittal for table of trace metals in various crudes).

Many other types of crude have historically been processed at HOVENSA, which are equally likely to show metals variability. Although HOVENSA does not presently have data on mercury in its crude oils or residual fuel oils, an excellent paper by Wilhelm and Spitz, Impact of Mercury on Crude Oil Quality, outlines expected variations in mercury content in various crude oils from Alberta, reporting orders of magnitude differences, as do other papers by this same author. Even light sweet crudes can have high mercury levels; Belanak from Indonesia has been reported to have 100 to 350 ppb. The sampling data in Attachment 2 shows nickel content for .3%S residual fuel to be approximately 31- 41 ppm, which is somewhat higher than nickel content of other .3%S resides in this database. HOVENSA does not even have the theoretical possibility to seek out lower metal fuels from other suppliers and must use what is produced or available at the refinery. (See submittal for sampling data)

EPA discussed in the preamble the Brick MACT case which considers this issue:
The majority opinion in the Brick MACT case does not address the
possibility of subcategorization to address differences in the HAP content of raw materials. However, in his concurring opinion Judge Williams stated that EPA's ability to create subcategories for sources of different classes, size, or type (CAA section
112(d)(1)) may provide a means out of the situation where the floor standards are achieved for some sources, but the same floors cannot be achieved for other
sources due to differences in local raw materials whose use is essential. (Id. At 884)
We believe that this opinion clearly allows EPA to establish a subcategory for remote/island facilities in this rule because they have the same potential issue of being unable to meet the Boiler MACT rule because of the local fuels available.

[Footnote 33: As noted above, mercury does not necessarily concentrate in residual fuel oil, because of its relative volatility.]
[Footnote 34: Platts Oilgram News, July 11, 2005]
[Footnote 35: HOVENSA plans on additional sampling. As noted above, HOVENSA anticipates that it will be prohibited from combusting low metals slurry oil in the future because of its sulfur content.]

Response: See preamble for discussion of a non-continental unit subcategory.

Commenter Name: Alicia Oman
Commenter Affiliation: National Association of Manufacturers
Document Control Number: EPA-HQ-OAR-2002-0058-2845.1
Comment Excerpt Number: 37

Comment: One additional subcategory that merits consideration is for “limited use” units. While the prior Boiler MACT rule treated units with average capacity factors of 10% or less separately, the proposed rule does not continue that approach. Instead, it presumes that limited use units are just like those operated full-time which burn a similar fuel. Limited use sources operate intermittently and for shorter periods of time (e.g., a backup hospital boiler that runs when other units are being fixed or a peaking unit used to supplement electric generation during particularly hot summer days). Compared to most boilers, these units spend a far greater percentage of their time starting up and shutting down. As a result, their emissions profiles differ markedly from sources which operate in efficient steady-state manners. For example, they are likely to experience higher CO levels as the boiler heats up due to incomplete combustion. Similarly, many pollution control technologies are either difficult to use or ineffective during startup and shutdown periods. These are just the sort of “class” and “type” distinctions which merit consideration for subcategorization under §112(d)(2). Given the limited and sporadic operation of emergency and backup boilers, as well as the technical infeasibility of imposing emission limitations on these units, the limited use subcategory should be limited by work practices in lieu of an emission floor.

The limited use subcategory adopted in EPA’s 2004 Boiler MACT final rule should be carried forward to the proposed rule.

The previous version of EPA’s Boiler MACT recognized that boilers used for emergencies or as backup boilers should be placed in a subcategory due to the limited and unscheduled nature of their use. See National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters; Final Rule, 69 Fed. Reg. 55218, 55232 (September 13, 2004). EPA recognized that “[t]he boiler database indicates that these infrequently operated units typically operate 10 percent of the year or less,” however, “[t]hese limited use boilers, when called upon to operate, must respond without failure and without lengthy periods of startup.” Id. Continued recognition of this subcategory is both supported by recent EPA action and practically justified.

Response: Please refer to the preamble for discussion of the limited use subcategory.

Commenter Name: Alicia Oman
Commenter Affiliation: National Association of Manufacturers
Document Control Number: EPA-HQ-OAR-2002-0058-2845.1
Comment Excerpt Number: 38

Comment: A limited use subcategory is supported by EPA's recent similar treatment of emergency and black start compression ignition engines.

In March of this year, EPA provided a similar subcategory in its final rule promulgating national emission standards for existing compression-ignition reciprocating internal combustion engines ("CI RICE") with a site rating of less than or equal to 500 brake horsepower. See National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines, 75 Fed. Reg. 9648 (March 3, 2010).

In that Rule, EPA recognized that stationary existing CI RICE should be divided into non-emergency and emergency categories "in order to capture the unique differences between these types of engines." Id. at 9650. Like the limited use boilers described in EPA's September 13, 2004 rule, EPA recognized that these emergency CI RICE are required to operate infrequently and for relatively short periods of time and must be kept in working order during prolonged periods of time when they are not operating.

EPA cited as justification for its emergency unit subcategorization an earlier memorandum titled Subcategorization and MACT Floor Determination for Stationary Reciprocating Internal Combustion Engines ?500 HP at Major Sources, Docket No. EPA-HQOAR-2008-0708-0006 (January 21, 2009). See National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines, 74 Fed. Reg. 9698, 9705 (March 5, 2009). This memorandum, in turn, incorporated by reference the rationale found in the memorandum Subcategorization of Stationary Reciprocating Internal Combustion Engines ?500 HP, Docket No. EPA-HQ-OAR-2005-0030-0012 (May 15, 2006), which enumerated four reasons for creating a subcategory for emergency CI RICE:

1. Emergency use units are used when electric power from the local utility is interrupted or becomes unreliable. The duration of the power outages is entirely beyond the control of the source, and, when they do occur (except in the case of a major catastrophe) they rarely last more than a few hours, often only a few minutes.

2. Emissions from these units are expected to be low on an annual basis; emissions occur only during emergency situations or for a very short time to perform maintenance checks and operator training. State and local regulators generally have not required emission controls for emergency power/limited use units.

3. Add-on catalytic control devices that are most applicable to reduce HAP from stationary RICE would be less effective on an annual basis for emergency use units, since emergency use units generally operate for brief periods. Therefore, a greater percentage of the emergency use units' operation, as compared to operation of peaking or baseload engines, will occur during catalyst warm-up, when the catalyst's effectiveness will be lower.

4. Emergency use units operate for very few hours per year. A survey conducted by the California Air Resources Board indicated that emergency engines are operated about 30 hours

per year. Also, the National Fire Protection Association requires 30 minutes per week (27 hours per year) to maintain and test emergency engines. The recently finalized Airborne Toxic Control Measure in California allows districts to approve up to 100 hours per year for maintenance and testing of emergency engines.

Id. at 5-6. [Footnote: While these criteria focus on an "emergency use" subcategory, it is important to note that the limited duration of the use, not the purpose for using the RICE is the key issue. For example, the same rule also creates a subcategory for "black start" engines (engines used to start a turbine generator), which operate during both "emergency and high demand days." National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters; Final Rule, 69 Fed. Reg. 55218 at 9662.]

These same criteria justify the establishment of a limited use Boiler MACT subcategory. First, limited use boilers, whether used as backup or emergency use boilers, are put into service only during unexpected failures of the main boiler or "when electric power from the local utility is interrupted or becomes unreliable" both of which are events "entirely beyond the control of the source." Id. at 5. Second, because of their limited use during the year, "[e]missions from these units are expected to be low on an annual basis." Id. Third, for this same reason, a greater percentage of a limited use boiler's annual operations will be during startup and shutdown, when emissions controls are less effective. See National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters, 75 Fed. Reg. at 32023. Finally, like emergency CI RICE, limited use boilers operate for only a small portion of the year, typically "10 percent of the year or less." National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters; Final Rule, 69 Fed. Reg. at 55232.

Like emergency and black start CI RICE, emergency and backup boilers should be placed into a subcategory that recognizes the unique challenges that would be faced monitoring and controlling emissions from these units.

Response: Please refer to the preamble for discussion of the limited use subcategory.

Commenter Name: Alicia Oman
Commenter Affiliation: National Association of Manufacturers
Document Control Number: EPA-HQ-OAR-2002-0058-2845.1
Comment Excerpt Number: 39

Comment: Limited use boilers cannot practically demonstrate compliance with standards set relying on continuously operating units.

In addition to the unique operating characteristics of limited use boilers, there are practical reasons for creating a limited use subcategory as well. As noted by Judge Williams in Sierra Club v. EPA, "Section 112(d)(1) authorizes the Administrator to 'distinguish among classes, types, and sizes of sources within a category or subcategory' . . . . [O]ne legitimate basis for creating additional subcategories must be the interest of keeping the relation between 'achieved' and 'achievable' in accord with common sense and the reasonable meaning of the statute." Sierra Club v. EPA, 479 F.3d 875, 884-85 (D.C. Cir. 2007) (Williams, J., concurring).

Without subcategorization for limited use boilers, these infrequently operated units will need to comply with the same emission limits set by units that operate on a continuous bases. As noted above, "combustion units operate most efficiently when operated at or near their design capacity. The combustion efficiency tends to decrease as the unit's load (steam production) decreases." National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters, 75 Fed. Reg. at 32023. Limited use boilers will therefore be operating for a significantly greater percentage of their time during periods of inefficient operation.

While EPA has already attempted to address this problem through the current MACT floor analysis by addressing the reduced efficiency of load-following units through allowances for variability. [Footnote: See MACT Floor Analysis (2010) for the Industrial, Commercial, and Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants – Major Source at 9-10 (April 2010).] this problem is further amplified for limited use boilers, which EPA did not address in its MACT floor analysis, due to EPA's decision to include periods of startup and shutdown in determining compliance with MACT. As found by EPA, this was justified because "the standards that we are proposing are daily or monthly averages. Continuous emission monitoring data obtained from best performing units, and used in establishing the standards, include periods of startup and shutdown. Boilers, especially solid fuel-fired boilers, do not normally startup and shutdown more the [sic] once per day. Thus, we are not establishing a separate emission standard for these periods because startup and shutdown are part of their routine operations and, therefore, are already addressed by the standards." Id. at 32013. [Footnote: Continuous emission monitoring data is not available for all pollutants in the database. To the extent that emission limits are based on stack test data that does not consider SSM events, emission information based on an operator's knowledge and engineering calculations can be used to incorporate SSM variability into the MACT Floor analysis.] Moreover, EPA found that "[p]eriods of startup, normal operations, and shutdown are all predictable and routine aspects of a source's operation." Id. Neither of these findings reasonably applies to emergency or backup boilers. First, as discussed above, emergency and backup boilers cannot practically make measurements over a monthly average given their limited utilization. Second, emergency and backup uses are by definition neither predictable nor routine.

By their very nature, emergency and backup boilers must spend a larger percentage of time in startup, shutdown, or other reduced-efficiency operating conditions than either base-loaded or load-following units. EPA should not require limited use boilers to comply with standards set by the best operated of these more efficient units.

Response: Please refer to the preamble for discussion of the limited use subcategory.

Commenter Name: Alicia Oman
Commenter Affiliation: National Association of Manufacturers
Document Control Number: EPA-HQ-OAR-2002-0058-2845.1
Comment Excerpt Number: 40

Comment: The limited use subcategory should be based on a capacity utilization of 10%.

For CI RICE, "[t]here is no time limit on the use of emergency stationary engines in emergency situations." Id. at 9654. This is a reasonable provision, since an emergency RICE must continue to operate as long as an emergency persists. This provision should similarly apply to limited use boilers. In addition, however, EPA recognized in the final CI RICE MACT rule that these units also need to operate in other, non-emergency situations, including for maintenance and participation in demand response programs. As a result, EPA allocated time within each operating year (100 hours) for emergency CI RICE to operate in non-emergency situations for what EPA referred to as "maintenance checks and readiness testing." Id. at 9654. In addition, EPA allocated 50 hours of each unit's maintenance and readiness time for other non-emergency uses, including at least 35 hours for non-financial uses and up to 15 hours for participation in emergency demand response programs, where the unit would be needed to provide power to a "regional transmission organization or equivalent balancing authority" and the "transmission operator has determined there are emergency conditions that could lead to a potential electrical blackout." Id. Examples of such conditions were also provided by EPA, including "unusually low frequency, equipment overload, capacity or energy deficiency, or unacceptable voltage level." Id.

Given the importance of demand response programs to averting blackouts and other emergencies, the State of Ohio recently went even further, expanding the definition of "emergency" in its permit-by-rule exemptions from MACT for emergency generators less than 50 horsepower to include:

Conditions where a regional transmission organization notifies electric distributors that an emergency exists or may occur and it is necessary to implement emergency procedures for voluntary load curtailments by customers within Ohio, in response to unusually low frequency, equipment overload, capacity or energy deficiency, unacceptable voltage levels, or other emergency conditions leading to a potential electrical blackout. . . .

Proposed Amendment to OAC 3745-31-03 (June 7, 2010); Executive Order 2010-07S (June 7, 2010) (adopting proposed amendment). As stated by Governor Strickland, "[i]n the event of an electrical grid failure that could result in widespread electrical blackouts, Emergency Load Response Programs allow emergency generator operators to temporarily utilize their generators without the need to obtain a permit to help prevent those blackouts. Allowing the use of emergency generators in such circumstances protects public health and welfare." Executive Order 2010-07S at ¶4. Further, Ohio has exempted all emergency electrical generators operating less than 500 hours per rolling 12-month period from obtaining a permit to install. See Proposed Amendment to OAC 3745-31-03.

For these same reasons, EPA should consider both the necessity of maintenance and readiness testing, as well as participation in emergency demand response programs and other “non-emergency” uses in setting the parameters for a limited use subcategory. While limits based on hours of operation like those used in the CI RICE MACT are one option, another and potentially easier standard to administer would be to rely on capacity utilization. Boilers, unlike RICE, cannot start up or shut down quickly, making it difficult for boiler operators to run a boiler for only a set number of hours. An hours-of-operation limit, therefore, would be less practical than a limit based on capacity utilization. Moreover, as EPA noted in the Proposed Rule, some emissions from boilers are not dependent on operating parameters such as hours operated, but rather on the fuel consumed. See National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines, 75 Fed. Reg. at 32017 (discussing fuel-dependent HAP). A capacity utilization factor of 10% was chosen for the previous Boiler MACT final rule as the best means of defining a limited use unit. See National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters; Final Rule, 69 Fed. Reg. at 55223. This definition is equally appropriate for the current rule.

Response: Please refer to the preamble for discussion of the limited use subcategory.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 75

Comment: EPA has broad discretion to establish subcategories of sources. Section 112 provides EPA with explicit authority "to establish subcategories under this section , as appropriate." [70 Fed. Reg. 59462 (October 12, 2005).] Indeed, section 112 establishes a presumption in favor of the creation and modification of categories and subcategories in the course of the Agency’ regulatory program, by mandating that EPA ‘shall from time to time, but no less often than every 8 years, revise, if appropriate, in response to public comment or new information, a list of all categories and subcategories of major sources."[Clean Air Act section 112 (c)(1); see also section 112 (c)(5) ("... the Administrator may at any time list additional categories and subcategories of sources."] section 112(c)(1). The fact that section 112 empowers EPA to establish subcategories without any limiting criteria confers a broad grant of authority. [Consumer Federation of America v. U.S. Dept. of Health and Human Services, 83 F.3d 1497 (D.C. Cir. 1996) (interpreting the phrase "as appropriate" in a more limiting statutory mandate as conferring substantial discretion).] Nothing in the Act or applicable case law suggests otherwise.

While EPA has nearly unfettered discretion to create subcategories as appropriate, the Act provides ample authority for EPA to distinguish among groups of sources within a source category or subcategory in setting a MACT standard. The statute provides that EPA "may distinguish among classes, types and sizes of sources within a category or subcategory" when establishing MACT standards.[42 U.S.C. section 7412(d)(1).] Congress" use of the broad terms "class," "type," and ‘size" shows that EPA is intended to have broad discretion in the appropriate factors that warrant distinguishing among sources, and EPA's proposed subcategories fall squarely within the meaning of "types" and 'sizes."

It is a well-established canon of statutory construction that courts "give the words of a statute their ordinary, contemporary, common meaning, absent an indication Congress intended them to bear some different import."70 [Williams v. Taylor, 529 U.S. 420, 431, 120 S.Ct. 1479, 1487-88, 146 L.Ed.2d 435 (2000).] The term "class" is typically defined to mean "a group, set or kind marked by common attributes or a common attribute."[Webster's Third New International Dictionary Unabridged (1993).] "Type" is defined as "qualities common to a number of individuals that serve to distinguish them as an identifiable class or kind,"[Id]. further clarifying that ""[t]ype", "kind" and 'sort" are usually interchangeable" and that ""kind" in most uses is likely to be very indefinite and involve any criterion of classification whatsoever." To the extent that EPA may distinguish among sources within a category or subcategory on the basis of "any [reasonable] criterion of classification whatsoever," and may create subcategories as appropriate, the CAA strongly supports EPA's authority to create subcategories of industrial boilers as proposed.

Response: See response to comment EPA-HQ-OAR-2002-0058-3213.1, excerpt 145 for EPA's authority to create subcategories.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 76

Comment: The legislative history makes clear that Congress intended EPA to distinguish among classes, types and sizes of sources in three circumstances: when differences among sources affect (1) the feasibility of air pollution control technology; (2) the effectiveness of air pollution control technology; and (3) the cost of control.

The Senate Report clarifies that the Administrator should:

...take into account factors such as industrial or commercial category, facility size, type of process and other characteristics of sources which are likely to affect the feasibility and effectiveness of air pollution control technology. Cost and feasibility are factors which may be considered by the Administrator when establishing an emission limitation for a category under section 112. The proper definition of categories, in light of available pollution control technologies, will assure maximum protection of public health and the environment while minimizing costs imposed on the regulated community. However, in limited circumstances where a group of sources may share the characteristics of other sources in the category, the Administrator may establish subcategories for such sources.[S. Rep. No. 228, 101st Cong., 1st Sess. 166].

Thus, in the view of the Senate, the standard for establishing categories and subcategories is essentially the same, although the Administrator is cautioned not to make too rampant use of subcategories.

The House Report similarly provides:

EPA may distinguish among classes, types and sizes of sources within a category or subcategory. . . . 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 measures, or to drive sources to the brink of shutdown. [House Rep. No. 101-490, Part 1, at 328.]

In sum, while Congress intended the MACT program to achieve significant emissions reductions, it also intended EPA to be cognizant of the costs of control, and to ensure that the program did not cause significant economic hardship. One primary mechanism for achieving this goal is through the use of subcategories, which enables the Agency to account for the fact that distinctions among classes, types and sizes of sources may have a very real impact on the feasibility of a given control technology, the effectiveness of that control technology, and the cost of control.

Response: See response to comment EPA-HQ-OAR-2002-0058-3213.1, excerpt 145 for EPA’s authority to create subcategories.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 77

Comment: The only case to interpret the "classes, types and sizes" language supports this interpretation. Sierra Club v. Costle [657 F.2d 298 (D.C. Cir. 1981).] recognized the broad discretion this language confers on EPA to create what in effect are subcategories of sources with differentiated emission standards. This decision interpreted identical statutory language found in the New Source Performance Standards (NSPS) provisions of section 111 of the CAA. Under the "classes, types and sizes" language, the Sierra Club court upheld a variable NSPS SO2 reduction requirement that was tied to a source’s existing SO2 emissions levels which, in turn, depended on the sulfur content of the facility’s fuel. The court noted that "[t]he required finding that must underlie a variable standard is much broader than a mere determination that uniformity is not achievable. Rather, EPA has the discretion to vary the standard upon finding that such a departure (from uniform control) does not undermine the basic purposes of the Act." [Id. at 321.]

On this basis, the court expressly upheld EPA’s subcategorization of coal-fired power plants based on the sulfur content of fuel, finding that "[c]ertainly the text of the statute nowhere forbids a distinction based on sulfur." [Bragdon v. Abbott, 524 U.S. 634, 645 (1998).] More generally, the Sierra Club decision confirms EPA’s discretion to set differentiated emissions standards for groups of sources within a category – i.e., for subcategories – even in instances where the strictest standard may be achievable by all sources.

The House Report further provides that "Nothing in this language authorizes the establishment of a category based wholly on economic grounds, nor is there any implication that individual facilities may be granted categorical waivers ... based on assertions of extraordinary economic effect." [id] In other words, the cost of control is an appropriate basis for distinguishing among sources so long as it is not the sole basis for distinction.

The court’s analysis in Sierra Club is relevant to an analysis of the authority granted to EPA through CAA section 112. Section 112 employs the same language as Section 111 in defining when EPA may promulgate distinct emission standards for sources within a category or subcategory. The Supreme Court consistently has held that "when administrative and judicial interpretations have settled the meaning of an existing statutory provision, repetition of the same language in a new statute indicates, as a general matter, the intent to incorporate its administrative and judicial interpretations as well." Therefore, section 112, which adopted section 111’s terms almost ten years after the D.C. Circuit issued the Sierra Club decision, must be understood to carry the settled meaning given to those terms by that decision.

EPA’s past practice has been consistent with this interpretation of the Act. The Agency has subcategorized sources in numerous industrial categories. From this experience, it is possible to distill several principles that have guided the Agency’s decision making with regard to creation of subcategories. First, EPA has determined that subcategorization is appropriate where sources use different processes, and those processes result in different types or concentrations of uncontrolled HAPs. Here, for example, the suite of pollutants emitted by solid-fueled boilers differs from that emitted by liquid-fueled boilers, which in turn differs from that emitted by gas-fueled boilers. For example, the types of metals emitted by solid-fueled boilers differ from the types of metals emitted by liquid-fueled boilers, and gas-fueled boilers typically emit little metals, but may emit more organic HAPs. [See 68 Fed. Reg. at 1670 (January 13, 2003).] Thus, subcategorization based on fuel type is appropriate because the different types of boilers emit different types of HAPs.

The Agency also has subcategorized sources based on size, where size differences affect the performance of control technologies, such as where more frequent start up and shut down makes it more difficult for smaller sources to maintain the same level of control as larger sources. That is also the case here. There are fundamental differences in the design of small boilers, as compared to large boilers. Moreover, smaller units often are used in swing load mode, whereas larger units more typically are baseloaded. These smaller boilers have more frequent start ups and shut downs that impact the performance of control technology, and hence the achievability of the standard. Thus, subcategorization of boilers based on size – or infrequent utilization – also is consistent with EPA’s past precedent and is appropriate because of the impact of these factors on the ability of these sources to maintain the same level of control as larger sources.

Furthermore, the Agency has subcategorized sources where differences among sources affect the applicability of control technology. For example, EPA created subcategories in the 1999 polyether polyols production MACT standard, finding that "[s]ubcategorization was necessary due to the distinctively different nature of the epoxide and THF processes and its effect on the applicability of controls." [64 Fed. Reg. 29421 (June 1, 1999).] Similarly, in the 1998 flexible polyurethane foam production MACT standard, EPA found that "[s]ubcategorization was necessary to reflect major variations in production methods, and/or HAP emissions that affect the applicability of controls."[61 Fed. Reg. 68407 (December 27, 1996).]
Based on similar rationales, EPA created subcategories in the Group I polymers and resins NESHAP and the primary aluminum production NESHAP, and proposed to create subcategories in the polyurethane foam production NESHAP. [See, e.g., 40 C.F.R. Part 63, Subpart III (Flexible Polyurethane Foam Production), 40 C.F.R. Part 63, Subpart LL (Primary Aluminum Reduction Plants), and 40 C.F.R. Part 63, Subpart U (Group I Polymers and Resins).] Here, for example, fabric filters may be an appropriate control technology to capture metals from coal-fired boilers, but are not appropriate for use on oil-fired boilers because the soot blinds the bags of the fabric filter, and is also a fire hazard. Thus, subcategorization based on fuel type is appropriate because the type of fuel affects the applicability of control technology.

In sum, the use of subcategorization in this rule is amply supported by the language of the statute, the legislative history, applicable case law, and the Agency's own past practices. With these principles in mind, we believe that further subcategorization is warranted.

Response: See response to comment EPA-HQ-OAR-2002-0058-3213.1, excerpt 145 for EPA's authority to create subcategories.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 81

Comment: EPA needs to establish a subcategory for "limited use" units. While the prior Boiler MACT rule treated units with average capacity factors of 10% or less separately, the proposed rule does not continue that approach.

Instead, EPA presumes that limited use units are just like those operated full-time which burn a similar fuel. Limited use sources operate intermittently and for shorter periods of time (e.g., small package boilers that are only used during plant outages, a backup boiler that runs when other units are being fixed, a peaking unit used to supplement electric generation during particularly hot summer days, a process heater that operates for a few hours at a time to warm up a heat transfer fluid for use in a chemical process, or a process heater that only operates intermittently in order to maintain the temperature of a process fluid in the desired range).

Compared to most boilers and process heaters, these units spend a far greater percentage of their time starting up and shutting down. As a result, their emissions profiles differ from sources which operate in efficient steady-state manners. For example, they are likely to experience higher CO levels as the boiler or process heater heats up due to incomplete combustion. Similarly, many pollution control technologies are either difficult to use or ineffective during startup and shutdown periods and would be cost prohibitive to install and use for only short periods of time during a year. These are just the sort of "class" and "type" distinctions which merit consideration for subcategorization under section 112(d)(2).

Because limited use boilers and process heaters do not operate on a regular schedule and typically operate for only short periods of time, emissions profiles for these boilers and process heaters can vary significantly from those of a similar boiler or process heater operating in a steady state. "Combustion units operate most efficiently when operated at or near their design capacity. The combustion efficiency tends to decrease as the unit’s load (steam production) decreases."[75 Fed. Reg. 32023.]

Given their short run times, there are also technological limitations on how effectively emissions from these units can be controlled, particularly for organic HAP emissions. EPA indicated in the response to comments on the original Boiler MACT rule that it could not identify any control technologies that would reduce organic HAP emissions for limited use boilers, and thus could not identify a technology or method to reduce organic HAP emissions. [See Response to Public Comments on Proposed Industrial, Commercial, and Institutional Boilers and Process Heaters NESHAP EPA-HQ-OAR-2002-0058-0649.] Finally, since "limited use boilers, when called upon to operate, must respond without failure and without lengthy periods of startup," [National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters; Final Rule, 69 Fed. Reg. 55218, 55232 (September 13, 2004).] a significantly larger percentage of their annual operation will be devoted to maintenance and readiness testing than other commercial, industrial, or institutional boilers. These differences noted in the 2004 boiler rule remain valid today and justify the creation of a subcategory for limited use boilers and process heaters.

Response: Please refer to the preamble for discussion of the limited use subcategory.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 82

Comment: In March of this year, EPA established a limited use subcategory in the rule promulgating national emission standards for existing compression-ignition reciprocating internal combustion engines ("CI RICE") with a site rating of less than or equal to 500 brake horsepower.[See National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines, 75 Fed. Reg. 9648 (March 3, 2010) (RICE rule).]

In the rule, EPA recognized that stationary existing CI RICE should be divided into non-emergency and emergency categories "in order to capture the unique differences between these types of engines." [Id. at 9650.] Like the limited use boilers in this rule and EPA’s 2004 boiler rule, EPA recognized that the emergency CI RICE are required to operate infrequently and for relatively short periods of time and must be kept in working order during prolonged periods of time when they are not operating.

As justification for its emergency unit subcategorization EPA cited an earlier memorandum titled ‘subcategorization and MACT Floor Determination for Stationary Reciprocating Internal Combustion Engines ?500 HP at Major Sources", Docket No. EPA-HQ-OAR-2008-0708-0006 (January 21, 2009). [Id. at 9705.] This memorandum, in turn, incorporated by reference the rationale found in the memorandum ‘subcategorization of Stationary Reciprocating Internal Combustion Engines ?500 HP", Docket No. EPA-HQ-OAR-2005-0030-0012 (May 15, 2006), which enumerated four reasons for creating a subcategory for emergency CI RICE:

Emergency use units are used when electric power from the local utility is interrupted or becomes unreliable. The duration of the power outages is entirely beyond the control of the source, and, when they do occur (except in the case of a major catastrophe) they rarely last more than a few hours, often only a few minutes.

Emissions from these units are expected to be low on an annual basis; emissions occur only during emergency situations or for a very short time to perform maintenance checks and operator training. State and local regulators generally have not required emission controls for emergency power/limited use units.

Add-on catalytic control devices that are most applicable to reduce HAP from stationary RICE would be less effective on an annual basis for emergency use units, since emergency use units generally operate for brief periods. Therefore, a greater percentage of the emergency use units" operation, as compared to operation of peaking or baseload engines, will occur during catalyst warm-up, when the catalyst’s effectiveness will be lower.

Emergency use units operate for very few hours per year. A survey conducted by the California Air Resources Board indicated that emergency engines are operated about 30 hours per year. Also, the National Fire Protection Association requires 30 minutes per week (27 hours per year) to maintain and test emergency engines. The recently finalized Airborne Toxic Control Measure in California allows districts to approve up to 100 hours per year for maintenance and testing of emergency engines. [Id. at 5-6.] [While these criteria focus on an "emergency use" subcategory, it is important to note that the limited duration of the use, not the purpose for using the RICE is the key issue. For example, the same rule also creates a subcategory for "black start" engines (engines used to start a turbine generator), which operate during both "emergency and high demand days." National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters; Final Rule, 69 Fed. Reg. 55218; Rice Rule, 75 Fed. Reg. at 9662.]

These same criteria justify the establishment of a limited use boiler and process heater subcategory. First, limited use boilers are put into service only during maintenance outages, unexpected failures of the main boiler, or "when electric power from the local utility is interrupted or becomes unreliable" and some of these events are "entirely beyond the control of the source. [Id. at 5.] Second, because of their limited use during the year, "[e]missions from these units are expected to be low on an annual basis." [Id.] Third, for this same reason, a greater percentage of a limited use boiler or process heater's annual operations will be during startup and shutdown, when emissions controls such as a CO catalyst are less effective. [See National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters, 75 Fed. Reg. at 32023.] Finally, like emergency CI RICE, limited use boilers and process heaters operate for only a small portion of the year, typically "10 percent of the year or less."[69 Fed. Reg. at 55232 (September 13, 2004).]

Like emergency and black start CI RICE, limited use units should be placed into a subcategory that recognizes the unique challenges that would be faced monitoring and controlling emissions from these units.

In addition to the unique operating characteristics of limited use boilers, there are practical reasons for creating a limited use subcategory. As noted by Judge Williams in Sierra Club v. EPA, 'section 112(d)(1) authorizes the Administrator to "distinguish among classes, types, and sizes of sources within a category or subcategory" . . . . [O]ne legitimate basis for creating additional subcategories must be the interest of keeping the relation between "achieved" and

"achievable" in accord with common sense and the reasonable meaning of the statute. Sierra Club v. EPA, 479 F.3d 875, 884-85 (D.C. Cir. 2007) (Williams, J., concurring). If EPA fails to establish a subcategory for limited use boilers, these infrequently operated units will be force to comply with the emission limits set by completely dissimilar units, i.e., units that operate on a continuous basis. This is contrary to the language and intent of section 112.

Response: Please refer to the preamble for discussion of the limited use subcategory.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 83

Comment: Combustion units operate most efficiently when operated at or near their design capacity. It is well known that combustion efficiency tends to decrease as the unit's load (steam production) decreases. Limited use units, by their nature, will therefore be operating for a significantly greater percentage of their time during periods of inefficient operation.

While EPA has already attempted to address periods of unavoidable inefficient operation in the current floor analysis by addressing the reduced efficiency of load-following units through allowances for variability, [See MACT Floor Analysis (2010) for the Industrial, Commercial, and Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants – Major Source at 9-10 (April 2010).]this problem is amplified for limited use boilers, which EPA did not address in its MACT floor analysis, due to EPA's decision to include periods of startup and shutdown in determining compliance with MACT. EPA justifies the inclusion of periods of startup and shutdown by proposing standards that are daily or monthly averages. EPA states:

Continuous emission monitoring data obtained from best performing units, and used in establishing the standards, include periods of startup and shutdown. Boilers, especially solid fuel-fired boilers, do not normally startup and shutdown more the [sic] once per day. Thus, we are not establishing a separate emission standard for these periods because

startup and shutdown are part of their routine operations and, therefore, are already addressed by the standards. [Id. at 32013.], [101 Id.]

Moreover, EPA found that "[p]eriods of startup, normal operations, and shutdown are all predictable and routine aspects of a source’s operation."101 While ACC presents comments relative to the inadequacy of the averaging periods relative to startup and shutdown periods elsewhere in these comments, neither of these findings reasonably applies to limited use units. EPA should not require limited use boilers to comply with standards set by best performing units that operate continuously.

Response: Please refer to the preamble for discussion of the limited use subcategory.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 84

Comment: EPA established a capacity utilization factor of 10% in the 2004 boiler rule as the best means of defining a limited use unit. [See National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters; Final Rule, 69 Fed. Reg. at 55223.] This definition is equally appropriate for the current rule.

Response: Please refer to the preamble for discussion of the limited use subcategory.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 85

Comment: Section 112(h) of the CAA allows EPA to promulgate a design, equipment, work practice, or operational standard, or combination thereof, if it is not feasible to prescribe or enforce an emission standard and this authority has been affirmed in the D.C. Circuit.103 [Sierra Club v. EPA, 479 F. 3d 875, 884 (D.C. Cir. 2007).] Given the limited and sporadic operation of emergency and backup boilers, as well as the technical infeasibility of imposing emission limitations on these units, EPA should establish work practices standard in lieu of emission limits for limited use units.

EPA also used its section 112(h) authority in the RICE rule to set work practices, including regularly scheduled maintenance and the cataloging of hours of operation, for emergency use engines. See RICE rule at 9655-56. As stated by EPA, "EPA believes that work practices are appropriate and justified for this group of stationary engines because the application of measurement methodology is not practicable due to technological and economic limitations."[Rice Rule, 75 Fed. Reg. at 9556.]

As further stated by EPA:

[U]sing these procedures would increase the required number of hours of operation of the engine beyond the routinely scheduled reliability testing and maintenance operation, thereby increasing emissions. While emergency engines have periods of operation for scheduled maintenance and reliability testing, those periods are usually several hours shorter than the number of hours that would be required to run the necessary emissions tests under subpart ZZZZ.[Id. at 9661.]

Similarly, as stated in the memorandum entitled "Existing Stationary Non-Emergency CI RICE Less Than 100 HP and Existing Stationary Emergency CI RICE Located at Major Sources and GACT for Existing Stationary CI RICE Located at Area Sources" (February 15, 2010) cited in EPA's final rule:

For existing stationary CI emergency engines located at major sources, EPA determined it is not feasible to prescribe or enforce an emission standard because the application of measurement methodology to this class of engine is impracticable due to the technological and economic limitations. Emergency engines typically only operate during emergencies or during periods of routine testing and maintenance. EPA determined that application of the emissions measurement methodologies during either of these periods is not practicable. It is impracticable to test emissions from stationary CI emergency engines during periods of routine testing and maintenance using the test procedures specified in the rule because it would increase the required number of hours of operation of the engine beyond the routinely scheduled reliability testing and maintenance operation, thereby increasing emissions. While emergency engines have periods of operation for scheduled maintenance and reliability testing, those periods are usually several hours shorter than the number of hours that would be required to run the necessary emissions tests under subpart ZZZZ. [Memorandum from Bradley Nelson and Tanya Parise, EC/R Incorporated to Melanie King, USEPA MACT Floor Determination for Existing Stationary Non-Emergency CI RICE Less Than 100 HP and Existing Stationary Emergency CI RICE Located at Major Sources and GACT for Existing Stationary CI RICE Located at Area Sources, February 15, 2010, Document ID: EPA-HQ-OAR-2008-0708-0327.]

EPA also excluded black start units from emission regulations in the RICE rule. While these units operate whenever a turbine generator starts, and therefore are not limited to emergency operations, EPA nonetheless recognized the importance of exempting these units from numeric standards, finding that "the short time of operation for these engines (10–15 minutes per start) makes application of measurement methodology for these engines using the required procedures, which require continuous hours of operation, impracticable. Requiring numerical emission standards for these engines would actually require substantially longer operation than would occur normally in use, leading to greater emissions and greater costs."[Id. at 9662.]

As EPA found, "[t]he majority of stationary CI engines are used for emergency purposes. EPA has estimated that 80 percent of stationary CI engines are emergency engines and EPA has taken steps in the final rule to reduce the burden on owners and operators of these engines." [Id. at 9658.] Rather, the basis for promulgating work practices in lieu of emission standards is the infeasibility of prescribing or enforcing an emission standard.109[See 42 U.S.C. section 7412(h).]

Emergency, startup, and backup boilers and process heaters, like emergency and black start CI RICE, are operated for only short periods of time and cannot feasibly be tested pursuant to EPA standards. Work practices should therefore also serve in lieu of emission monitoring and control technology for emergency, startup and backup boilers. For example, under section 63.7545(d) of this proposed rule , a Notification of Intent must be submitted at least 30 days before any performance test. As a result, even if a limited use boiler were operated for an entire month after an unplanned start, there would be no time to conduct the necessary performance tests. In addition, most test methods require steady state conditions that may not be achieved during limited use operations and, once a steady state has been reached, would require the boiler to continue operating at steady state for enough time to conduct the three 4-hour test runs required by the proposed rule for most compliance tests. [See proposed section 63.7520(d). Even during regular operation, a limited use boiler would still need to operate for at least 12 hours in steady state condition in order to accommodate the variability attendant in these performance tests. See National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters, 75 Fed. Reg. at 32033 (stating that EPA selected a 12 hour averaging period for demonstrating continuous compliance "to reflect operating conditions during the performance test to ensure the control system is continuously operating at the same or better level as during a performance test demonstrating compliance with the emission limits").] Some limited use process heaters will not be able to be operated for the amount of time necessary to accommodate an emissions test if they serve a distinct role of heating a process fluid, as the process fluid cannot be overheated.

Similarly, EPA is proposing in this rule that boilers and process heaters with heat input capacities greater or equal to 100 MMBtu/hr demonstrate that average CO emissions, on a 30-day rolling average, are at or below the proposed CO limit. This averaging period is essential to accommodating expected data variability, including SSM events.[See, e.g. National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters; Final Rule, 69 Fed. Reg. at 5521. See also Response to Public Comments on Proposed Industrial, Commercial, and Institutional Boilers and Process Heaters NESHAP at 102 (rejecting a 24-hour averaging period because a 30-day rolling average "accounts for the variability in fuel characteristics (e.g., moisture, Btu content, mixture) that occur for solid fuel-fired boilers and process heaters").] Without the ability to test for 30 continuous days or thereabouts, a limited use unit cannot be expected to meet the same emission limits due to their reduced ability to accommodate data variability, and operators cannot adequately determine compliance with numeric emission limits.

The result would be a marked inability to practically measure emissions without operating these units for significant periods of time for the sole purpose of conducting emissions testing. As with the recently regulated emergency CI RICE, this would result in a new increase in emissions through the very effort to control emissions from these units. [RICE Rule, 75 Fed. Reg. at 9655-56.] Work practices are therefore the most feasible control for limited use boilers and process heaters and should be adopted in the final rule.

Response: Please refer to the preamble for discussion of the limited use subcategory.

Commenter Name: Lee B. Zeugin
Commenter Affiliation: Utility Air Regulatory Group
Document Control Number: EPA-HQ-OAR-2002-0058-2880.1
Comment Excerpt Number: 97

Comment: The electric utility industry utilizes boilers that burn either natural gas or distillate oil and may be subject to EPA's proposed Subpart DDDDD. These units are called auxiliary boilers ("Aux Boilers") and typically are operated only a limit number of hours (e.g., on the order of 1,000) in a calendar year. An Aux Boiler is used to generate the steam that is necessary to bring a main electric generating unit (EGU) on line. Since many electric utility boilers use various stream-driven equipment (e.g., feed water pumps, induced draft fans, etc.), the units cannot be brought online without an independent supply of steam. If a power plant has only one EGU, then it almost certainly must use its Aux Boiler to bring the main unit online. Power plants that have multiple EGUs may also have Aux Boilers, but those Aux Boilers are often not needed because of inter-steam piping among the EGUs. That is, an EGU can be brought online utilizing the steam generated in another EGU, which is already online. Such Aux Boilers tend to have very low capacity factors.

As stated above, the electric utility industry burns either natural gas or distillate oil in their Aux Boilers. Natural gas is the fuel of choice, but all power plants do not have access to pipeline natural gas service. Therefore, these plants must rely on distillate oil. For units with limited service, like utility Aux Boilers, EPA's proposed work practice standards for units that burn natural gas may be more than is needed, but it is neither cost prohibitive nor technical infeasible. On the other hand, the proposed compliance provisions appear unreasonable for limited use boilers that burn distillate oi1.24 First, Aux Boilers are not going to and should not need to employ control technology to meet the emission limits when burning a clean fuel like ultra-low sulfur diesel (ULSD). Second, because the demand for an Aux Boiler to operate is almost impossible to forecast, it is almost a certainty that each Aux Boiler subject to proposed Subpart DDDDD would have to be operated some time during each year for the sole purpose of emission testing. Such an outcome would constitute very poor public policy because: (1) unnecessary air pollutants would be generated; (2) unnecessary carbon emissions would occur; and (3) a valuable and not unlimited resource (ULSD diesel) would be wasted. Since there is no control technology to verify the performance of, a work practice (boiler tune-up) would be a reasonable approach for limited-use boilers that burn clean fuel.

Response: Please refer to the preamble for discussion of the limited use subcategory.

Commenter Name: Brad James
Commenter Affiliation: Trinity Consultants
Document Control Number: EPA-HQ-OAR-2002-0058-2853.1
Comment Excerpt Number: 1

Comment: EPA should establish a subcategory specific to bagasse boilers, wholly separate from all other biomass boilers. A separate subcategory is warranted because bagasse boilers are different in kind from other biomass boilers based on fuel type and boiler design—the two criteria that EPA has offered to explain its current subcategorizations. See 75 Fed. Reg. 32,017; see also Sierra Club v. EPA, 479 F.3d 875, 885 (D.C. Cir. 2007) (Williams, J., concurring) (EPA's "authority to generate subcategories" is only "limited by the usual ideas of reasonableness").

EPA notes the following in the proposed rule: "EPA has attempted to identify subcategories that provide the most reasonable basis for grouping and estimating the performance of generally similar units using the available data. We believe that the subcategories we selected are appropriate. EPA requests comments on whether additional or different subcategories should be considered. Comments should include detailed information regarding why a new or different subcategory is appropriate (based on the available data or adequate data submitted with the comment), how EPA should define any additional/different subcategories, how EPA should account for varied or changing fuel mixtures, and how EPA should use the available data to determine the MACT floor for any new or different categories." See 75 Fed. Reg. 32,017.

The establishment of emission limits for the broad "biomass" subcategory does not accurately reflect the wide variation of emissions anticipated for the primary type of biomass fuel combusted at the Clewiston facility (bagasse). Similar source has previously been defined by EPA as: "a stationary source or process that has comparable emissions and is structurally similar in design and capacity to a constructed or reconstructed major source such that the source could be controlled using the same control technology." See 40 CFR §63.41.

There are four factors to consider when defining similar sources (or subcategories): 1) comparable emissions, 2) structurally similar in design, 3) structurally similar in size, and 4) capable of control using the same control technology.

The separation into subcategories by the broad classification of "biomass" fuel is complicated by the multi-fuel nature of many biomass boilers. FSI has submitted extensive comments on this topic. As those submissions make clear, bagasse has important differences from other biomass fuels. Most notably, bagasse contains approximately 50% moisture and has very low density (compared to other dry biomass such as hog fuel, which EPA also grouped into "biomass" fuel).

The difference in combustion of wet and dry fuel is significant. Wet fuels such as bagasse require more heat to evaporate the inherent moisture, which directly impacts the emissions of CO and PM (and the HAP for which they are surrogates). Thus, the combustion of bagasse does not result in “comparable emissions” to other forms of biomass, and bagasse has failed the first factor of being defined a similar source with other biomass. FSI’s submissions also show that bagasse boilers are designed differently than other biomass boilers. Bagasse boilers also are fully integrated with the sugar mill in the continuous milling process. These differences, as well as several others that FSI’s comments cover in depth, call for separate regulatory treatment of bagasse boilers. U.S. Sugar adopts FSI’s comments and refers EPA to FSI’s submissions.

Response: See response to comment EPA-HQ-OAR-2002-0058-1841.1, excerpt 2 for bagasse boiler subcategory.

Commenter Name: John T. Heard
Commenter Affiliation: The Virginia Coal Association
Document Control Number: EPA-HQ-OAR-2002-0058-2953.1
Comment Excerpt Number: 3

Comment: Industrial boilers that have specialized uses and are therefore operated infrequently should be listed in a separate subcategory. Such auxiliary boilers are often operated primarily during plant startups, and as such emit very low levels of HAPs. These boilers should be categorized as those with a 10 percent capacity factor for the maximum hourly heat input, and should be subject to a work practice standard under Section 112(h) of the CAA.

Response: Please refer to the preamble for discussion of the limited use subcategory.

Commenter Name: Robert Thornton
Commenter Affiliation: International District Energy Association
Document Control Number: EPA-HQ-OAR-2002-0058-2918.1
Comment Excerpt Number: 20

Comment: EPA should establish a subcategory for "limited use" units due to their significant differences from steady-state units
In the preamble discussion, it appears that the EPA intended to provide that a natural gas-fired boiler that receives less than 10% of the annual heat-input from liquid fuels would be considered a natural gas-fired boiler for purposes of regulation under the MACT rule, and thus only subject to the annual tune-up requirements. However, the proposed restricts the use of liquid fuels to periods of testing or supply curtailment.

This is problematic and inappropriate because “plant-side” equipment may require the use of liquid fuels to provide for maintenance of natural gas systems during periods that do not constitute emergencies as narrowly defined in the proposed rule.

Response: Please refer to the preamble for discussion of the limited use subcategory.

See response to comments EPA-HQ-OAR-2002-0058-2840.1, excerpt 12 and EPA-HQ-OAR-2002-0058-2875.1, excerpt 9 for use of back up fuels within Gas 1 units and appropriateness of 10% fuel use limit.

Commenter Name: Sarah E. Amick
Commenter Affiliation: Rubber Manufacturers Association
Document Control Number: EPA-HQ-OAR-2002-0058-2941.1
Comment Excerpt Number: 28

Comment: A Limited Use Subcategory is Supported by EPA's Recent Similar Treatment of Emergency and Black Start Compression Ignition Engines. In March of this year, EPA provided a similar subcategory in its final rule promulgating national emission standards for existing compression-ignition reciprocating internal combustion engines ("CI RICE") with a site rating of less than or equal to 500 brake horsepower. See National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines, 75 FR 9648 (March 3, 2010).

In that Rule, EPA recognized that stationary existing CI RICE should be divided into non-emergency and emergency categories "in order to capture the unique differences between these types of engines." Id. at 9650. Like the limited use boilers described in EPA's September 13, 2004 rule, EPA recognized that these emergency CI RICE are required to operate infrequently and for relatively short periods of time and must be kept in working order during prolonged periods of time when they are not operating.

EPA cited as justification for its emergency unit subcategorization an earlier memorandum titled Subcategorization and MACT Floor Determination for Stationary Reciprocating Internal Combustion Engines ?500 HP at Major Sources, Docket No. EPA-HQ-OAR-2008-0708-0006 (January 21, 2009). See National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines, 74 Fed.Reg. 9,698, 9,705 (March 5, 2009). This memorandum, in turn, incorporated by reference the rationale found in the memorandum Subcategorization of Stationary Reciprocating Internal Combustion Engines ?500 HP, Docket No. EPA-HQ-OAR-2005-0030-0012 (May 15, 2006), which enumerated four reasons for creating a subcategory for emergency CI RICE: "Emergency use units are used when electric power from the local utility is interrupted or becomes unreliable. The duration of the power outages is entirely beyond the control of the source, and, when they do occur (except in the case of a major catastrophe) they rarely last more than a few hours, often only a few minutes".

Emissions from these units are expected to be low on an annual basis; emissions occur only during emergency situations or for a very short time to perform maintenance checks and operator training. State and local regulators generally have not required emission controls for emergency power/limited use units.

Add-on catalytic control devices that are most applicable to reduce HAP from stationary RICE would be less effective on an annual basis for emergency use units, since emergency use units generally operate for brief periods. Therefore, a greater percentage of the emergency use units' operation, as compared to operation of peaking or baseload engines, occurs during catalyst warm-up, when the catalyst's effectiveness is lower.

Emergency use units operate for very few hours per year. A survey conducted by the California Air Resources Board indicated that emergency engines are operated about 30 hours per year. Also, the National Fire Protection Association requires 30 minutes per week (27 hours per year) to maintain and test emergency engines. The recently finalized Airborne Toxic Control Measure in California allows districts to approve up to 100 hours per year for maintenance and testing of emergency engines. Id. at 5-6. [While these criteria focus on an "emergency use" subcategory, it is important to note that the limited duration of the use, not the purpose for using the RICE is the key issue. For example, the same rule also creates a subcategory for "black start" engines (engines used to start a turbine generator), which operate during both "emergency and high demand days." National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters; Final Rule, 69 Fed.Reg. 55218 at 9662.]

These same criteria justify the establishment of a limited use boiler MACT subcategory. First, limited use boilers, whether used as backup or emergency use boilers, are put into service only during unexpected failures of the main boiler or "when electric power from the local utility is interrupted or becomes unreliable" both of which are events "entirely beyond the control of the source." Id. at 5. Second, because of their limited use during the year, "[e]missions from these units are expected to be low on an annual basis." Id. Third, for this same reason, a greater percentage of a limited use boiler's annual operations will be during startup and shutdown, when emissions controls are less effective. See National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters, 75 Fed.Reg. at 32,023. Finally, like emergency CI RICE, limited use boilers operate for only a small portion of the year, typically "10 percent of the year or less." National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters; Final Rule, 69 Fed.Reg. at 55232.

For example, the City of Painesville operates one municipal utility boiler that only operates when the primary unit goes down or during periods of high demand when additional power generation is necessary to maintain the reliability of power to the City and basic services, such as police stations, fire departments, and hospitals. Between 2004 and 2008, this boiler operated for an average 583.5 hours per year, operating only during 15 months of that five-year span and for periods ranging from as little as 15.25 hours in a month to as much as 588.25 hours. This boiler would clearly meet the definition of a limited use boiler. Even assuming operation at maximum capacity throughout its entire operation, it would have emitted less than 1/10 its potential emissions but would have been in periods of startup or shutdown 15 times longer than a continuously operated boiler.

Like emergency and black start CI RICE, emergency and backup boilers like Painesville's Boiler #3 should be placed into a subcategory that recognizes the unique challenges that would be faced monitoring and controlling emissions from these units.

Response: Please refer to the preamble for discussion of the limited use subcategory.

Commenter Name: Paul J. Allen
Commenter Affiliation: Constellation Energy
Document Control Number: EPA-HQ-OAR-2002-0058-3164
Comment Excerpt Number: 1

Comment: Constellation supports sub-categorization. Standards synthesized from different units may be impossible to meet in practice by any one unit. Boilers with different designs, such as bubbling bed or circulating fluidized bed (CFB), and associated varying control technologies, such as multi-done and Electrostatic precipitator (ESP), emit varying quantities of NOx, CO, PM, and VOCs. They also have varying fuel sources with fluctuating quality. Therefore, selecting the lowest emission limit per constituent from various different boiler units may not be an accurate reflection of any individual operating boiler. It is unreasonable to require an individual unit to meet all of the lowest limits compiled from multiple boilers of different design technologies

Response: See response to comment EPA-HQ-OAR-2002-0058-3213.1, excerpt 145 for EPA's authority to create subcategories.

See preamble for response to comment on the pollutant-by-pollutant approach.

Commenter Name: Alicia Oman
Commenter Affiliation: National Association of Manufacturers
Document Control Number: EPA-HQ-OAR-2002-0058-2845.1
Comment Excerpt Number: 35

Comment: The Clean Air Act provides EPA with discretion to subcategorize based on size,type and class of source.

CAA 112(c)(1) instructs EPA to establish "categories and subcategories" of sources for regulation under Section 112. CAA 112(d)(1) then further provides that EPA "may distinguish among classes, types and sizes of sources within a category or subcategory" when establishing MACT standards. These provisions vest EPA with the clear authority to group like units for purposes of establishing emissions limitations. EPA's subcategorization decisions, however, must turn on legitimate "class" "type" or size" distinctions as required by 112(d).

The legislative history explains what Congress meant when it authorized EPA to distinguish among sources by “class” “type” or “size.” The relevant Senate Report indicates that EPA should:

[T]ake into account factors such as industrial or commercial category, facility size, type of process and other characteristics of sources which are likely to affect the feasibility and effectiveness of air pollution control technology. Cost and feasibility are factors which may be considered by the Administrator when establishing an emission limitation for a category under Section 112 . . . where a group of sources may share the characteristics of other sources in the category, the Administrator may establish subcategories for such sources.

S. REP. NO. 228, 101st Cong., 1st Sess. 166 (emphasis added).

That language has two key implications. First, it confirms that Congress’ use of the broad concepts of “class” “type” or “size” was meant to allow subcategorization based on (and require consideration of) a broad array of factors. That is particularly true given Congress’ open-ended statement that EPA should consider “other characteristics of sources” when grouping them for purposes of establishing emissions limits. Second, this statement confirms that, while cost issues alone may not be sufficient to require subcategorization, costs are relevant to subcategorization decisions. See also, Id. (indicating that subcategorization “wholly on economic grounds” is inappropriate) (emphasis added). By clarifying that individual facilities may not be granted categorical waivers “based on assertions of extraordinary economic effect,” id., the Senate Report confirms that the threat of severe economic consequences on a subgroup sharing other common attributes supports subcategorization.11

Thus, 112(d)(2) authorizes (and requires) EPA to consider differences in “commercial category, facility size, type of process and other characteristics” that may affect: (1) feasibility of control technology, (2) effectiveness of control technology, and (3) costs of control. Where those factors are present, subcategorization is warranted.

Response: See response to comment EPA-HQ-OAR-2002-0058-3213.1, excerpt 145 for EPA’s authority to create subcategories.

Commenter Name: Wayne Brandt
Commenter Affiliation: Minnesota Forest Industries
Document Control Number: EPA-HQ-OAR-2002-0058-3220
Comment Excerpt Number: 12

Comment: Many facilities, including Minnesota forest products industries, have backup boilers that operate only when the primary units are down due to malfunction or maintenance. Typically, back-up boilers operate at 10% or less of annual capacity. The cost to upgrade a small package boiler is estimated by AF&PA to be $10 million. It is not cost-effective to add-on expensive pollution control equipment for sources that operate at 10% or less annually. In addition, testing protocols would require operation when the boilers are not needed. EPA should include a subcategory for limited use boilers, or a de minimis applicability threshold for small or limited use units.

Response: Please refer to the preamble for discussion of the limited use subcategory.

Subcategories: Coal

Commenter Name: John C. Hendricks
Commenter Affiliation: American Electric Power
Document Control Number: EPA-HQ-OAR-2002-0058-2703.1
Comment Excerpt Number: 2

Comment: EPA Should Consider Additional Subcategories for Industrial Boilers. AEP encourages EPA to more fully use its discretion in providing for sub-categorization in determining the MACT limits. In particular, AEP would like the EPA to recognize the variability in "coal" and provide differing MACT limits for bituminous, sub-bituminous, and lignite, and recognized, as the EPA has done in the past, that there are substantial differences in the coal ranks. Boilers are designed for a specific type of coal and are unable to change fuels. The proposed limits should account more fully for this variability by adding additional subcategories. While AEP does not operate any coal fired Industrial Boilers, AEP has concerns with this approach in anticipation of the upcoming Electric Generating Unit (EGU) MACT.

Response: See response to comment EPA-HA-OAR-2002-0058-2808.1, excerpt 12 for further subcategorization based on coal rank.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 86

Comment: While EPA did consider a wider range of units for variability in coal, variability in coal quality occurs within individual seams and within one unit's supply, which may come from different sources, and EPA's testing did not account for this difference in fuel quality. If considering variability in fuel quality across different types of fuel within a single subcategory is too difficult, that may be an indication that EPA should subcategorize based on fuel types down to specific fuels and materials. Additional subcategorizing within fuel groups may be particularly warranted here, given that EPA has (rightfully) ruled out fuel switching, which would in any event be impossible for many regulated sources. Section 112(d)(1) authorizes the Administrator to "distinguish among classes, types and sizes of sources within a category or subcategory," and the Agency's discretion in identifying these subcategories quite broad, perhaps simply "limited by the usual ideas of reasonableness." See Brick MACT, 479 F.3d at 885 (Williams, J., concurring).

Response: See response to comment EPA-HA-OAR-2002-0058-2808.1, excerpt 12 for further subcategorization based on coal rank.

Commenter Name: G. Vinson Hellwig and Robert H. Colby
Commenter Affiliation: National Assocation of Clean Air Agencies
Document Control Number: EPA-HQ-OAR-2002-0058-2841.1
Comment Excerpt Number: 24

Comment: Within the Boiler MACT “coal-fired” category, EPA proposes separate subcategories for stoker, fluidized bed and pulverized coal designs. However, we know of no reason why well-controlled units of these designs should differ significantly in levels of HAP emissions. EPA’s subsequent MACT floor analysis leads to calculated MACT floor levels that are often identical and are within the variability expected of such measurements, thus documenting the lack of a basis for a separate subcategory.

Response: See response to comment EPA-HQ-OAR-2002-0058-2880.1, excerpt 89.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 158

Comment: Subcategories are needed for new source coal boiler standards. The proposed new source standards are unrealistic and, if left unchanged, could seriously endanger the nation’s long-term prospects for growth in the manufacturing sector. Reports we hear from suppliers of boilers and air pollution control systems are that they will not be able to supply commercial guarantees to meet the proposed standards. Additional subcategories which focus on the regional fuel supplies (Powder River Basin, Illinois Basin, Central Appalachian, etc) are needed to allow future boilers to be installed across the nation. For example, the top performer used to set the HCl standard for new coal-fired boilers is a boiler which burns sub-bituminous coal, which inherently has much lower chlorine content than eastern coals. A facility on the east coast should not have to meet standards that can be met only by burning a fuel only obtained from hundreds if not thousands of miles away. EPA should not set new source standards that prohibit certain coal types. The US Geological Survey has a coal quality database that can be examined for coal pollutant content information. http://energy.er.usgs.gov/products/databases/CoalQual/index.htm

Response: See response to comment EPA-HA-OAR-2002-0058-2808.1, excerpt 12 for further subcategorization based on coal rank.

EPA disagrees that additional subcategories are needed for new sources to further incorporate fuel quality. Fuel variability was incorporated into the new source floor values when data was available for the single best performing unit.

Commenter Name: William A. Moore
Commenter Affiliation: Luminant
Document Control Number: EPA-HQ-OAR-2002-0058-2780.1
Comment Excerpt Number: 6

Comment: EPA should further subcategorize fuel types to include subcategories based on coal rank.
As explained above, Luminant also has an interest in the methodology behind the proposed rule as it relates to EPA's process for developing MACT standards and how that process might impact the EGU MACT standards currently under development. Again, Luminant supports EPA's subcategorization of units based on fuel type and combustion processes. For the same reasons EPA has subcategorized units based on fuel burned, EPA should create subcategories based on coal rank. Units should be further subcategorized by the geographic location from which the coal is mined. EPA has the authority to subcategorize based on coal rank and should exercise that authority, given "that there are sufficient differences in the design and operation of utility boilers utilizing the different coal ranks to justify subcategorization by major coal rank." See 70 Fed. Reg. 28,606, 28,613 (May 18, 2005) (original NESHAP for EGUs).

For example, Texas lignite features relatively high ash content that can be highly alkaline. Texas lignite also has lower levels of chloride and higher levels of mercury when compared with other coal ranks. Furthermore, the mercury content of Texas lignite can vary greatly not only from mine to mine, but from seam to seam. Lignite is a very volatile fuel and has relatively low volatile organic compound emissions but may have higher carbon monoxide emissions due to boiler design and/or low NOX controls. Thus, while units designed to burn Texas lignite may be able to meet acid gas, volatile organic HAP, and dioxin floors, they may have great difficulty in meeting overly stringent mercury and non-mercury metals floors. If EPA proceeds with setting floors for individual HAPs or HAPs categories, then subcategories need to be established for individual coal ranks and, in some cases, mining locations.

As the D.C. Circuit has explained, "[i]f factors other than MACT technology do indeed influence a source's performance, it is not sufficient that EPA considered sources using only . . . MACT controls . . . ." Sierra Club v. EPA, 479 F.3d 875, 882 (D.C. Cir. 2007) (internal citations omitted). Thus, EPA must consider non-technology factors, i.e., fuel content, that affect emission levels when developing floor limits. See id. at 883. Given the significantly different characteristics of lignite and other coal ranks, EPA should create additional subcategories for units burning each coal rank.

Response: See response to comment EPA-HA-OAR-2002-0058-2808.1, excerpt 12 for further subcategorization based on coal rank.

Commenter Name: William A. Moore
Commenter Affiliation: Luminant
Document Control Number: EPA-HQ-OAR-2002-0058-2780.1
Comment Excerpt Number: 10

Comment: EPA's appropriate policy choice in this regard – that fuel-switching is not an appropriate control technology – logically and necessarily supports adding a lignite subcategory. Without such a subcategory, if NESHAPs are established in whole or in part upon non-lignite fuel, a lignite-burning unit would have to switch fuels to another (distantly-mined, in lieu of locally-mined) type of coal.

Response: See response to comment EPA-HA-OAR-2002-0058-2808.1, excerpt 12 for further subcategorization based on coal rank.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-2702.1
Comment Excerpt Number: 15

Comment: While EPA did consider a wider range of units for variability in coal, variability in coal quality occurs within individual seams and within one unit's supply, which may come from many different sources, and EPA's testing did not account for this difference in fuel quality. If considering variability in fuel quality across different types of fuel within a single subcategory is too difficult, that may be an indication that EPA should subcategorize based on fuel types down to specific fuels and materials. Additional subcategorizing within fuel groups may be particularly warranted here, given that EPA has (rightfully) ruled out fuel switching, which would in any event be impossible for many regulated sources. Section 112(d)(1) authorizes the Administrator to "distinguish among classes, types and sizes of sources within a category or subcategory," and the Agency's discretion in identifying these subcategories quite broad, perhaps simply "limited by the usual ideas of reasonableness." See Brick MACT, 479 F.3d at 885 (Williams, J., concurring).

Response: See response to comment EPA-HA-OAR-2002-0058-2808.1, excerpt 12 for further subcategorization based on coal rank.
EPA assessesed fuel variability from top performing units, based on the fuel analysis data provided to EPA.

Commenter Name: Chris M. Hobson
Commenter Affiliation: Southern Company
Document Control Number: EPA-HQ-OAR-2002-0058-2741.1
Comment Excerpt Number: 11

Comment: The Clean Air Act allows the Administrator to distinguish among “classes, types, and sizes of sources” when developing standards under Section 112. Nowhere in Section 112 does it limit EPA to only basing subcategories to instances where the class, type, or size has an effect of emissions. However, in the proposed rule, EPA has indicated that the subcategories are warranted because “differences between given types of units can lead to corresponding differences in the nature of emissions and the technical feasibility of applying emission control techniques”. While Southern Company does not disagree with this statement, we do disagree that EPA must only subcategorize if the class, type, or size has an effect on emissions.

Southern Company agrees with EPA’s decision to set a large number of subcategories in the proposed IB MACT rule; however, the number of subcategories that EPA chose is not sufficient and should be expanded to distinguish between various coal ranks. Historical testing has shown that coal rank has a significant effect on mercury and HCl emissions. EPA should further subcategorize coal-fired boilers based on coal rank (bituminous, subbituminous, lignite, etc.).

Response: See response to comment EPA-HA-OAR-2002-0058-2808.1, excerpt 12 for further subcategorization based on coal rank.

Commenter Name: John W. Fainter, Jr.
Commenter Affiliation: Association of Electric Companies of Texas
Document Control Number: EPA-HQ-OAR-2002-0058-2790.1
Comment Excerpt Number: 3

Comment: Support for subcategorization of boilers and process heaters

AECT commends EPA for considering differences in combustion technology by creating subcategories in the lB MACT proposed rule; however, EPA should have also created subcategories by coal rank. Historical testing has shown that coal rank has a significant effect on mercury and HC1 emissions. Failure to do so confounds the practical compliance ability of any facility due to the illogical approach of setting limits based on the performance of control technology in isolation of the facility as a source.

Response: See response to comment EPA-HA-OAR-2002-0058-2808.1, excerpt 12 for further subcategorization based on coal rank.

Commenter Name: Mike T.W. Carey
Commenter Affiliation: Ohio Coal Association
Document Control Number: EPA-HQ-OAR-2002-0058-2878.1
Comment Excerpt Number: 4

Comment: Although the Proposed Rules recognize boiler units are designed for a particular fuel type, the Proposed Rules fail to account for boiler units which are designed to burn a particular coal type. 75 Fed. Reg. 32006, 320117. As U.S. EPA knows, boilers are designed for a particular coal type. The chemical distinctions among the various types of coal make it nonsensical for U.S. EPA to set one uniform emission standard for coal.

Response: See response to comment EPA-HA-OAR-2002-0058-2808.1, excerpt 12 for further subcategorization based on coal rank.

Commenter Name: Ben Brandes
Commenter Affiliation: National Mining Association
Document Control Number: EPA-HQ-OAR-2002-0058-2787.1
Comment Excerpt Number: 9

Comment: EPA Should Identify More Subcategories of Coal-fueled and Specialized Industrial Boilers

Section 112(d)(1) of the Clean Air Act (CAA) states that, in promulgating regulations establishing emission standards for major sources, the "Administrator may distinguish among classes, types, and sizes of sources within a category or subcategory in establishing such standards." Section 112(c)(1) also states that, while "categories and subcategories listed under this subsection shall be consistent with the list of source categories established pursuant to Section 111 of this title," nothing in that statement "limits the Administrator's authority to establish subcategories under this section, as appropriate."

In coal-fueled industrial boiler units, testing has clearly indicated that coal rank has a significant effect on the emission levels of HCl and mercury. Low-rank coals such as lignite and sub-bituminous coals have higher moisture levels and lower carbon and energy levels, whereas high-rank coals such as bituminous and anthracite colas have lower moisture levels and higher carbon and energy levels. These qualities of the various types of coal have a direct effect on the resulting HCl and mercury emissions of the boilers that use them as feedstock. Therefore, pursuant to Section 112(d)(1), multiple subcategories should be created in the coal-fueled industrial boiler category based upon the particular type of coal combusted by the unit.

Response: See response to comment EPA-HA-OAR-2002-0058-2808.1, excerpt 12 for further subcategorization based on coal rank.

Commenter Name: Douglas A. McWilliams
Commenter Affiliation: American Municipal Power
Document Control Number: EPA-HQ-OAR-2002-0058-2808.1
Comment Excerpt Number: 12

Comment: EPA created subcategories for all pollutants based on fuel type, recognizing that "design, operating, and emissions infbrmation . .. indicates differences in unit design that distinguish di Iferent types of boilers." 75 Fed. Reg. at 32016-17. EPA determined that differences between units combusting coal, biomass, liquid fuel, natural/refinery gas, and process gas impacted emissions and warranted separate subcategories and emissions limits for each fuel type. Id. at 32017. For certain HAP, EPA expressly stated that emissions are -dependent upon the composition of the fuel." Id.

AMP agrees with EPA’s conclusion that fuel is an important factor affecting emissions; however, EPA’s subcategories do not go far enough in that they fail to account for significant differences in fuel composition within each proposed fuel subcategory. EPA should further subcategorize where distinct ranks of fuel exist. That is particularly important for the coal subcategories. Coal-fired units burn well-known ranks of coal, including bituminous, sub-bituminous, lignite, and anthracite. These distinct coal types have different chemical compositions that directly impact emissions of regulated pollutants. These differences may make it impossible for units burning a particular rank of coal to meet emission limits that are based on the combustion of different coal ranks.

For example, notable differences in mercury and chlorine content exist between the various coal ranks. Sub-bituminous coal has an average mercury content that is less than half of anthracite coal and significantly less than the other fuel ranks. See Comments from Domtar Industries, Inc. at 67 Tbl. 3 (Mar. 14, 2003) (EPA-HQ-OAR-2002-0058-0387) (citing Electric Power Research Institute, An Assessment of Mercury Emissions from U.S. Coal-Fired Power Plants (Sept. 2000)). Thus, basing emission limits on data from all units regardless of coal rank would result in floors set by units that happened to be combusting low-mercury coal during testing that is not universally usable. This leaves the rest of the source subcategory without a clear pathway to attain the MACT floor emission level particularly when control technology cannot reduce the uncontrolled emission rate sufficiently to meet the MACT floor emission limit. A similar problem exists regarding HCl limits. Bituminous coal contains more than three times the average chlorine of any of the other coal ranks. Id. These differences render general MACT floors based on all coal combustion unrepresentative and would make it exceptionally difficult (and perhaps impossible) for sources that burn coal ranks with higher mercury or chlorine content to achieve the resulting limits, even when operating the same controls used at best-performing sources. {Footnote: Consider HCI at the MACT emission limit of 0.02 lb/mmBtu after scrubber controls on a sub-bituminous coal-fired unit. Assuming HCI control efficiency at 99%, the uncontrolled rate is 2.0 lb/mmBtu. A comparable bituminous coal-fired unit would be expected to have three times the uncontrolled HCI emission rate, or 6.0 lb/mmBtu. Applying scrubber controls at 99% control efficiency would yield controlled emissions of .06 lb/mmBtu, which is three times higher than the MACT floor emission rate. Compliance is unachievable through control measures.]

Nor is coal switching a viable option since coal rank goes to the heart of unit design. Coal-fired boilers are specialized units that are designed to operate effectively burning a particular type of coal. Based on its unique expertise designing and adapting boilers, Babcock & Wilcox explains that "the deposition and erosion potential of the ash are the primary design considerations driving the overall size and arrangement" of coal-fired boilers. Steam, Its Generation and Use (Babcock & Wilcox) at 21-1. That is true because:

The effective utilization of fossil fuels for power generation depends to a great extent on the capability of the steam generating equipment to accommodate the inert residuals of combustion, commonly known as ash. The quantity and characteristics of the ash inherent to a particular fuel type are major concerns to both the designer and the operator of the equipment.

Id. Ash deposition and slag deposits cause numerous problems in boilers including reduced heat absorption, increased exit gas temperature (which causes additional slagging), fouling in convection banks, and dangerous slag buildups that can become dislodged and fall, causing failure of furnace tubes and other equipment damage.

To protect against these concerns, boilers are designed to accommodate the ash creation potential of the coal that will be used. Specifically, boilers that burn sub-bituminous or lignite coals must be designed with "ample clearance . . . between the burners and furnace walls as well as the furnace hopper and arch" which are "keyed to the slagging classification of the coal." Id. at 21-15. Boilers that burn higher ash coal are larger, with increased depth "to control slagging by reducing the input per plan area" and "side space dimensions" which "depend on the fouling classification of the coal" with higher ash coals requiring wider spacing. Id. at 21-16. Further, bank depths are established in part "as a function of fouling potential. . . . " Id. In other words, boilers must be designed larger to accommodate the higher ash content sub-bituminous and lignite coals that are mined primarily in the western United States.

These key differences preclude boilers designed to burn bituminous coal from simply switching to lower grades. For example, most units located in the Midwest are designed smaller to efficiently burn the high Btu, low ash bituminous coal that is locally available. Although bituminous coal has higher average mercury content than other types of coal, these units cannot simply turn to other, lower mercury, coal ranks to meet emission limits. Rather, their design and dimensions dictate that, to operate properly and avoid fouling, they must use higher-Btu bituminous coal. That renders these units technically incapable of meeting mercury levels that can be achieved by boilers that burn sub-bituminous and lignite coal with lower average mercury content.

This is precisely the situation that Congress intended, and the courts recognized, as ripe for subcategorization to bridge the gap between what is achieved and achievable within the MACT source category. The D.C. Circuit has also recognized the importance of achievability in reviewing MACT standards and has expressly confirmed that subcategorization is an important tool to help ensure that MACT standards are achievable in practice. Sierra Club, 375 U.S. App. D.C. at 238 ("[O]ne legitimate basis for creating additional subcategories must be the interest in keeping the relation between ‘achieved’ and ‘achievable’ in accord with common sense and the reasonable meaning of the statute."). Without subcategorization according to the different coal ranks, many units will find themselves unable to meet emission limits even with installation of MACT controls. As such, subcategorization by coal rank is necessary and warranted.

Response: The EPA disagrees with the commenters suggestion to further subcategorize solid fuel units based on the type of coal burned. The EPA recognizes the variation in emissions between different coal types, as well as difference within each coal type, and differences between coal and other solid fuels. However, the EPA also does not see any justification for any further subcategorization. Although there may be variation in the amount of pollutants emitted, the type of pollutants emitted will be similar between all solid fuel units (particulate matter, metallic

HAP, and inorganic HAP). As a result, similar control technologies may be used. The EPA also considers that variability has been incorporated into the MACT floor analysis because the emission limits developed for the MACT floor level of control incorporate boilers using various fuels, various combustor types, and variations of the same control device.

Commenter Name: Alicia Oman
Commenter Affiliation: National Association of Manufacturers
Document Control Number: EPA-HQ-OAR-2002-0058-2845.1
Comment Excerpt Number: 31

Comment: While EPA did consider a wider range of units for variability in coal, variability in coal quality occurs within individual seams and within one unit's supply, which may come from different sources, and EPA's testing did not account for this difference in fuel quality. If considering variability in fuel quality across different types of fuel within a single subcategory is too difficult, that may be an indication that EPA should subcategorize based on fuel types down to specific fuels and materials. Additional subcategorizing within fuel groups may be particularly warranted here, given that EPA has (rightfully) ruled out fuel switching, which would in any event be impossible for many regulated sources. Section 112(d)(1) authorizes the Administrator to "distinguish among classes, types and sizes of sources within a category or subcategory," and the Agency's discretion in identifying these subcategories quite broad, perhaps simply "limited by the usual ideas of reasonableness." See Brick MACT, 479 F.3d at 885 (Williams, J., concurring).

Response: See response to comment EPA-HA-OAR-2002-0058-2808.1, excerpt 12 for further subcategorization based on coal rank.

Commenter Name: John T. Heard
Commenter Affiliation: The Virginia Coal Association
Document Control Number: EPA-HQ-OAR-2002-0058-2953.1
Comment Excerpt Number: 2

Comment: EPA should identify more subcategories of coal-fired and specialized industrial boilers.

Section 112(d)(1) of the Clean Air Act (CAA) states that, in promulgating regulations establishing emission standards for major sources, the "Administrator may distinguish among classes, types, and sizes of sources within a category or subcategory in establishing such standards." Section 112(c)(1) also states that, while "categories and subcategories listed under this subsection shall be consistent with the list of source categories established pursuant to Section 111 of this title," nothing in that statement "limits the Administrator's authority to establish subcategories under this section, as appropriate."

In coal-fired industrial boiler units, testing has clearly indicated that coal rank has a significant effect on the emission levels of HC1 and mercury. Low-rank coals such as lignite and sub-bituminous coals have higher moisture levels and lower carbon and energy levels, whereas high-rank coals such as bituminous and anthracite coals have lower moisture levels and higher carbon and energy levels. These qualities of the various types of coal have a direct effect on the resulting HC1 and mercury emissions of the boilers that use them as feedstock. Therefore, pursuant to Section 112(d)(1), multiple subcategories should be created in the coal-fired industrial boiler category based upon the particular type of coal burned by the unit.

Response: See response to comment EPA-HA-OAR-2002-0058-2808.1, excerpt 12 for further subcategorization based on coal rank.

Commenter Name: Mary L. Frontczak
Commenter Affiliation: Peabody Energy
Document Control Number: EPA-HQ-OAR-2002-0058-2897.1
Comment Excerpt Number: 2

Comment: EPA proposes to establish strict MACT standards for coal-fueled boilers.Additionally, boilers and process heaters need only burn at least 10 percent coal on an annual average heat input basis to be classified in the coal category. EPA, however, did not propose MACT standards for owners or operators of boilers or process heaters which combust natural gas or refinery gas. Instead, EPA proposed a "work practice" standard that would be applied to those units. This work practice standard would require only that owners or operators of such boilers perform a tune-up and art energy assessment in order to comply with this rule.

According to EPA, these work practice requirements will reduce cumulative emissions from natural gas-fueled units by a meager 212.21 tons. In contrast, the emission limits applied to coal-fueled units will result in those units being forced to reduce their total tons per year of emissions by a cumulative 53,717.1 tons.

Response: See the preamble for discussion of how EPA selected work practice standards for gas 1 units.

Commenter Name: Bill Wemhoff
Commenter Affiliation: National Rural Electric Cooperative Association
Document Control Number: EPA-HQ-OAR-2002-0058-2835.1
Comment Excerpt Number: 8

Comment: NRECA commends EPA for creating a large number of subcategories in the proposed IB MACT rule. However, NRECA believes EPA should have created even more subcategories.

Historical testing has shown that coal rank has a significant effect on Hg and HCl emissions.

Response: See response to comment EPA-HA-OAR-2002-0058-2808.1, excerpt 12 for further subcategorization based on coal rank.

Commenter Name: Lee B. Zeugin
Commenter Affiliation: Utility Air Regulatory Group
Document Control Number: EPA-HQ-OAR-2002-0058-2880.1
Comment Excerpt Number: 9

Comment: Section 112(d)(1) of the CAA allows the Administrator to distinguish among "classes, types, and sizes of sources" in establishing MACT standards. This subcategorization language mirrors earlier language found in CAA § 111(b)(2).[In CAA § 112(c)(1), Congress provided that, to the extent practicable, the categories and subcategories under § 112 "shall be consistent with the list of source categories" under § 111.] In providing EPA discretion to create subcategories, § 112(d)(1) does not restrict subcategorization to cases where the "class", "type" or "size" factors affected HAP emissions. The provision merely requires EPA to establish regulations for each category or subcategory on the schedules set out in § 112. Indeed, EPA has not previously subcategorized under § 111 based solely on emission effects. For example, under § 111 EPA has subcategorized boilers on the basis of size (heat input) or the type of fuel burned (coal, oil or gas). These subcategorization decisions were based on feasibility and/or cost considerations, not on the level of emissions.

UARG commends EPA for creating a large number of subcategories in the proposed IB MACT rule. However, EPA should have created more subcategories. Historical testing has shown that coal rank has a significant effect on Hg and HCl emissions. Also, as discussed in section K below, a limited use subcategory should be created for industrial boilers that are operated infrequently because of their specialized nature and use.

Response: See response to comment EPA-HA-OAR-2002-0058-2808.1, excerpt 12 for further subcategorization based on coal rank.

Commenter Name: David O'Keefe
Commenter Affiliation: USEC, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-3122
Comment Excerpt Number: 9

Comment: Subcategories. The coal subcategories should be broken down by fuel type i.e., anthracite, bituminous, and subbituminous. There are inherent differences in HAP content for these different coal types. As noted on page 32010, "the presence or absence of HAP in fuel materials must be accounted for in establishing floors * * *."

Response: See response to comment EPA-HA-OAR-2002-0058-2808.1, excerpt 12 for further subcategorization based on coal rank.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 78

Comment: The Clean Air Act authority granted to EPA for proper subcategorization is applicable to fuel types among a fuel class. Specifically, coal types such as anthracite, bituminous, subbituminous, and lignite are well known to have different constituent levels and overall fuel properties. EPA has identified these differences in their NSPS regulations for steam generating units by setting limits for certain pollutants based on coal type. The properties of the different coal types can require differing furnace configuration, firing method, equipment design, and even emissions control equipment, since the coal properties affect the applicability and effectiveness of some emissions controls. When setting emission limits at or near the limits of detection, differences between fuel type become more important. This is especially notable relative to the mercury and chlorine contents generally seen in different coal types (i.e., subbituminous coal can have much lower Cl and Hg content than bituminous coal).

At a minimum, additional subcategories are needed for new source coal boiler standards. The proposed new source standards are unrealistic and, if left unchanged, could seriously endanger the nation's long-term prospects for growth in the manufacturing sector. Reports we hear from suppliers of boilers and air pollution control systems are that they will not be able to supply commercial guarantees to meet the proposed standards. Additional subcategories which focus on the regional fuel supplies (Powder River Basin, Illinois Basin, Central Appalachian, etc.) are needed to allow future boilers to be installed across the nation. For example, the top performer used to set the HCl standard for new coal-fired boilers is a boiler which burns sub-bituminous coal, which inherently has much lower chlorine content than eastern coals. A facility on the east coast should not have to meet standards that can be met only by burning a fuel only obtained from hundreds if not thousands of miles away. EPA should not set new source standards that prohibit certain coal types. The US Geological Survey has a coal quality database that can be examined for coal pollutant content information. [Available at http://energy.er.usgs.gov/products/databases/CoalQual/index.htm]

Response: See response to comment EPA-HA-OAR-2002-0058-2808.1, excerpt 12 for further subcategorization based on coal rank.
EPA acknowledges the additional data suggestions for coal quality, but the current methodology for assessing fuel variability requires EPA to link the emissions of best performing units with their variability. In our fuel variability analysis we focused on fuel analysis data that was reported to be fired at a specific best performing unit and we did not consider general fuel quality data that was not attibributed to best performing units.

Commenter Name: Lee B. Zeugin
Commenter Affiliation: Utility Air Regulatory Group
Document Control Number: EPA-HQ-OAR-2002-0058-2880.1
Comment Excerpt Number: 89

Comment: As discussed above, the Agency identified five basic types of units as subcategories for the three HAP groups that EPA termed fuel-dependant (i.e., PM , HCl and Hg). However, we do not believe EPA's analysis was sufficiently detailed, especially with respect to PM emissions. For coal-fired units, EPA subsequently identified three additional subcategories for organic emissions: (1) pulverized coal (PC) units; (2) stokers designed to burn coal; and (3) fluidized bed units designed to burn coal. The way the coal is prepared/processed for these three types of furnaces is fundamentally different. While potential PM (fly ash) emissions may be fuel dependent, an identical PM control technology (e.g., electrostatic precipitator) will perform quite differently on a stoker unit as compared to a PC unit. For a PC unit, the fuel must be ground to a fine powder (i.e., pulverized) in the coal mills before being blown into the furnace. On the other hand, stoker boilers take in much larger-sized pieces of coal. Because PC units require the fuel to be so fine, the PM emissions are more difficult to control. Likewise, fluidized bed units require yet a different coal preparation and also require the addition of limestone to the combustion bed. The characteristics of fluidized bed combustion yield uncontrolled PM emissions that are different from both PC units and stoker boilers. Because these different types of units process the coal differently, their PM emission characteristics are fundamental different. For example, a baghouse installed on a stoker unit could reduce PM emissions to a level that is barely measureable. On the other hand, that same baghouse installed on a similarly-sized PC unit would have higher PM emissions simply because finer coal particles are required by the PC burners. We do not believe the Agency adequately addressed this issue; rather, EPA appears to have simply assumed that all three furnace types should be treated equally with respect to the PM emission limit for coal combustion.

Response: The EPA disagrees with the commenters suggestion to further subcategorize for particulate matter emissions from solid fuel units based on the design of the combustor. Although there may be variation in the amount of pollutants emitted, the type of pollutants emitted will be similar and similar control technologies may be used. EPA recognizes that some units may obtain a higher removal efficiency but other units may be able to install control devices in parallel to meet similar emission limits.

Commenter Name: Michael Hutcheson
Commenter Affiliation: Ameren Services
Document Control Number: EPA-HQ-OAR-2002-0058-2803.1
Comment Excerpt Number: 16

Comment: Ameren believes coal fired boilers should also be subcategorized based on coal rank as the firing of different ranks of coals results in markedly different control technology requirements.

Response: See response to comment EPA-HA-OAR-2002-0058-2808.1, excerpt 12 for further subcategorization based on coal rank.

Subcategories: Biomass

Commenter Name: Houston Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1876
Comment Excerpt Number: 64

Comment: EPA should consider a subcategory
for green biomass, which -- since it combusts
differently than dry biomass.

Response: See response to comment EPA-HQ-OAR-2002-0058-2692.1, excerpt 2.

Commenter Name: Michael L. Steele
Commenter Affiliation: CraftMaster Manufacturing, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-1907.1
Comment Excerpt Number: 2

Comment: The biomass subcategories are poorly defined which raises doubts if USEPA has properly categorized the Boilers and Process Heaters into each subcategory. Then the units that make up the MACT Floor for each subcategory are suspect as well. Definitional issues and related questions include:

Stokers are defined in §63.7515 as mechanical stokers that are not typically used for biomass. stokers are widely used for wood biomass and seem to be defined under Boiler in the proposed regulations.

Are air-swept stoker fired units included in the Stoker subcategory or the Suspension Burner! Dutch Oven subcategory?

Are Suspension Boilers (definition) the same as Suspension Burners (subcategory)?

A Suspension Burner for biomass is typically like a Pulverized Coal Burner where the fuel is conveyed to the boiler by an airstream and burned in suspension.

Does the subcategory Suspension Burner! Dutch Oven include both Dutch Ovens and Suspension Burners! or must a unit employ both firing methods to be included?

It is surprising that a Suspension Burner (like pulverized coal) and a Dutch Oven would have similar combustion-related emissions and be in the same subcategory. It would seem that Dutch Ovens would have more in common with Fuel Celfs in that both types are pile burners.

How does a Dutch Oven differ from a Fuel Cell as far as combustion characteristics and combustion-related emissions?

What criteria is used to place a unit in a subcategory that employs more than one biomass firing method?

Response: See final rule and preamble for revised definitions of subcategories and how to determine the subcategory for units that employ multiple firing types. We have adjusted the definition of stoker. We have retained a combined dutch oven/suspension burner category. Emissions of CO are similar between the two designs and there is not ample technical reasons provided for separating these two designs into their own unique subcategories.

Commenter Name: Arlington Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1779
Comment Excerpt Number: 28

Comment: One of our major concerns with the proposal is the affect of the rules on wood-fired boilers commonly used in the furniture industry.
Under current practices boilers in the furniture industry are typically small and combust a kiln-dried wood fuel which is generated during the furniture manufacturing process.

The wood fuel is very dry, burns cleanly, has a neutral CO_2 emissions scoring and has a high BTU value. However, as we understand it, the Boiler Rule EPA has proposed would combine these smaller dry-wood fuel boilers used in the furniture industry into a broader biomass subcategory that includes boilers fired by wet fuel used in other industry sectors thereby creating a single subcategory of emission sources for evaluation.

By establishing a single large group of boilers that use both dry wood fuel and wet wood fuel, EPA effectively ignores the benefits and unique characteristics of dry wood boilers by imposing a single set of emissions standards on the entire category.

Large boilers burning wet biomass fuels have historically required costly controls as a result of their inherently higher emissions. The cost for small dry fuel boilers to meet standards that have historically applied to wet biomass boilers is prohibitive.

Currently, for that same boiler in North Carolina we estimate a cost of about $1.5 million to retrofit that boiler with a scrubber add-on control end of pipe to continue operation of that boiler in North Carolina. And the incremental air quality benefit that would come from lumping dry fuel boilers into such a category is neglible. In fact, rather than make costly investments in new controls -- control facilities, a more likely outcome is that furniture manufacturers will retire their wood-fire boilers, replace them with natural gas or fuel oil combustion boilers and simply dispose of the dry wood fuel generated by the furniture manufacturing processes in landfills.

As greenhouse gas neutral fuels would be replaced by a fuel that emits substantial amounts of greenhouse gases, we estimate that at this same typical facility in North Carolina an increase in CO_2 to switch to natural gas of 10,500 tons annually.

This predictable outcome would not be consistent with the intent of the rule. To prevent this likely outcome from occurring, we request that EPA revisit the proposal and establish a distinct low moisture biomass subcategory for dry wood fuel.

Having this subcategory which considers the unique characteristics of these boilers and the heat content of dry wood fuel would enable a far more desirable economic environmental outcome.

Response: See response to comment EPA-HQ-OAR-2002-0058-2692.1, excerpt 2. EPA cannot consider costs in determing the MACT floor.

Commenter Name: Arlington Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1779
Comment Excerpt Number: 31

Comment: [Question from Panelist] I think I've got this small dry fuel boiler subcategory to distinguish it from the larger biomass category.
In your opinion do we have the data currently to make such a distinction, or would that be something you might be submitting additional data on?
MR. PERDUE: No, we will submit additional data, but we do believe, Mr. Wayland, that you do have within your AP-42 factor a very distinct emission factor for dry fuel that the AHFA at the time the AFMA participated with EPA in developing. So, that data set should be there.
And like I said, there is a very distinct already subcategory for dry wood fuel.

Response: See response to comment EPA-HQ-OAR-2002-0058-2692.1, excerpt 2.

Commenter Name: Michael L. Steele
Commenter Affiliation: CraftMaster Manufacturing, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-1907.1
Comment Excerpt Number: 33

Comment: Definition of Biomass Fuel §63.7575

Please clarify the definition to include board mill residues such as sawdustJ sander dust, scrap board, etc.

Response: See the final ruel for a revised definition of biomass.

Commenter Name: Troy Runge
Commenter Affiliation: Wisconsin Bioenergy Initiative
Document Control Number: EPA-HQ-OAR-2002-0058-2353.1
Comment Excerpt Number: 8

Comment: Revise the standards for biomass. We believe new standards based on fuel type, type of boiler and type of use need to be expanded. Consider woody biomass vs. agricultural biomass, geographical variance in mercury and HCl content (some areas of the country grow wood and agricultural fuels that contain lower levels of these pollutants), and whether any control technology would reduce emissions to the new limits.

Response: EPA disagrees that further subcategorization is justified based on the type of biomass. Limited data are available for each biomass type and further subcategorization would over partition the database. Further, many solid fuel units co-fire multple types of solid fuels including combinations of bio-based solid and fossil solids as well as several different types of bio-based solids.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 153

Comment: Boilers labeled as burning deinking residuals should be placed in the appropriate biomass subcategory.
Biomass boilers burning salt laden wood also deserve special consideration, as these boilers will find it difficult to achieve the biomass HCl and dioxin limits due to increased chloride content in the wood.

Response: See response to comment EPA-HQ-OAR-2002-0058-2807.1, excerpt 2.

Commenter Name: David A. Buff
Commenter Affiliation: Golder Associates Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2801.1
Comment Excerpt Number: 7

Comment: FSI strongly agrees with these statements. However, for these same reasons, FSI strongly believes the biomass subcategory should be divided further into at least three subcategories for not only organic hazardous air pollutant (HAP) emissions, but also for PM emissions.

FSI believes that significant emission differences occur between wet and dry biomass. Certainly biomass containing more than 40 percent moisture will combust very differently than 30 percent or less moisture biomass, and the boiler design will take this difference into account. Bagasse contains between 48 percent and 55 percent moisture, which results in much different emissions for bagasse versus other wet biomass such as wood, which has on average lower moisture content. Just as coal and biomass are solid fuels that burn differently, and therefore their associated boiler design is different, so it is with wet and dry biomass fuels.

Although the HAP metals emissions are not dependent on wet versus dry biomass types, PM emissions are affected by moisture content of the fuel, since moisture content affects combustion efficiency and excess air levels, which in turn affects unburned carbon emissions. Unburned carbon, as well as ash in the biomass fuel, becomes entrained in the boiler flue gases and is measured as PM at the boiler stack. The lower combustion efficiency increases total PM emissions out the stack, but the HAP metals emissions are not increased, since the HAP metals will be emitted out the stack as PM (ash) regardless of unburned carbon amounts or combustion efficiency.

Response: See repsonse to comment EPA-HQ-OAR-2002-0058-2692.1, excerpt 2.

The EPA disagrees with the commenters suggestion to further subcategorize for particulate matter emissions from solid fuel units based on the moisture content of the fuel. Although there may be variation in the amount of pollutants emitted, the type of pollutants emitted will be similar and similar control technologies may be used. EPA recognizes that some units may obtain a higher removal efficiency but other units may be able to install control devices in parallel to meet similar emission limits. Further, many solid fuel units co-fire multiple types of solid fuels including combinations of both wet and dry biomass and biomass and coal or other fossil solids.

Commenter Name: Sheila C. Holman
Commenter Affiliation: North Carolina Department of Environment and Natural Resources
Document Control Number: EPA-HQ-OAR-2002-0058-2798.1
Comment Excerpt Number: 10

Comment: EPA should further subcategorize biomass on the basis of green (or wet) and dry fuels. NC DAQ test data show that PM emissions from dry wood (<20% moisture) combustion can be up to 20-50% higher than emissions from the combustion of green wood. In North Carolina, dry wood is burned in smaller boilers (<50 MM Btu/hr) in wood working industries, including furniture manufacturing. Green wood combustion sources include larger boilers (>250

MM Btu/hr) in lumber mills and pulp and paper plants that are more highly controlled. NC DAQ thinks that the dry wood-fired sources and green wood-fired sources are sufficiently different based on emissions and level of control to warrant additional sub-categorization.

Response: See response to comment EPA-HQ-OAR-2002-0058-2692.1, excerpt 2.

Commenter Name: Paul F. Perlwitz
Commenter Affiliation: Nippon Paper Industries USA Co.
Document Control Number: EPA-HQ-OAR-2002-0058-2807.1
Comment Excerpt Number: 2

Comment: NPIUSA is located at the base of a spit surrounded on three sides by marine waters. The mill's source of wood fuels includes forest biomass sourced and/or stored adjacent to marine waters. As a result of this proximity to marine waters for both the mill and its fuel supplies, the higher level of chlorides in the wood and air possibly present a different emissions profile than non? coastal mills. EPA should consider the performance of coastal mills and consider whether these mills should be considered in a separate category due to regional issues. Additional testing of boilers is needed to determine the effect of marine proximity to those whose fuel sources are substantial inland.

Response: There are 36 biomass boilers in coastal areas that have reported stack test data below the new source limit and 55 biomass boilers in coastal areas below the existing source limit for the solid fuel subcategory. Based on this, EPA determined it has adequately accounted for coastal biomass fuel variability in the development of the floors for the solid fuel subcategory.

Commenter Name: Bill Perdue
Commenter Affiliation: American Home Furnishings Alliance
Document Control Number: EPA-HQ-OAR-2002-0058-2692.1
Comment Excerpt Number: 2

Comment: Kiln dried wood fuel has very different combustion characteristics than "wet" biomass and, as a result, our clean-burning dry biomass fuel has been assigned a unique AP-42 emission factor for air emissions characterization. Due to its lower emission rate for particulate matter (as compared to bark and wet biomass fuels typical of paper mills), dry biomass units have not historically been required to install the more complex, more costly emission controls common on wet biomass units. The typical dry biomass unit uses mechanical separation devices such as multicyclones as the only necessary pollution control. However, wet biomass units are frequently required to install higher efficiency control devices such as electrostatic precipitators to meet New Source Performance Standards. Historically, dry biomass units have been categorized separately from their wet biomass counterparts, and for good reason.

Under Clean Air Section 112(d)(1), EPA has explicit authority to develop emission standards for appropriate subcategories. Even the U.S. Court of Appeals for the D.C. Circuit has recognized the breadth and utility of the subcategorization approach:

Section 112(d)(1) authorizes the Administrator to "distinguish among classes, types and sizes of sources within a category or subcategory," and the language of subsections 112(d)(2) and (3) pervasively refers to standards for sources in each "category or subcategory." The authority to generate subcategories is obviously not unqualified; at the least it must be limited by the usual ideas of reasonableness. And there is not necessarily any guarantee that, even with suitable subcategorization, every source will be able to achieve standards that meet a lawful application of § 112(d)(3) to reasonably defined subcategories. Nonetheless, one legitimate basis for creating additional subcategories must be the interest in keeping the relation between "achieved" and "achievable" in accord with common sense and the reasonable meaning of the statute. [Sierra Club v. EPA, 479 F.3d 875 (D.C. Cir. 2007) (J. Wiliams, concurring).]

By lumping dry and wet biomass units into a single "Biomass" category, the EPA has failed to recognize the unique attributes of our bona fide fuel category. Because dry fuel combustion units have historically not required complex control, our category is distinct from other biomass units in its emission characteristics for particulate matter. Precedence for subcategorizing broadly-defined fuel types has been established in the rule by EPA's designation of "Gas 1" and "Gas 2" categories. We request the development of a separate category for dry biomass fuels based on the same principle.

Response: The EPA disagrees with the commenters suggestion to further subcategorize solid fuel units based on the moisture content of the fuel. Although there may be variation in the amount of pollutants emitted, the type of pollutants emitted will be similar and similar control technologies may be used. EPA recognizes that some units may obtain a higher removal efficiency but other units may be able to install control devices in parallel to meet similar emission limits. Further, many solid fuel units co-fire multiple types of solid fuels including combinations of both wet and dry biomass and biomass and coal or other fossil solids. EPA also notes that what has historically been required under older permits does not necessarily reflect a MACT level of control and MACT subcategories do not need to be identical to the breakdowns used in the AP-42 program.

Commenter Name: Ted Michaels
Commenter Affiliation: Energy Recovery Council
Document Control Number: EPA-HQ-OAR-2002-0058-2831.1
Comment Excerpt Number: 7

Comment: EPA should further subcategorize biomass units by combustor type for setting organic HAP MACT floors.

ERC supports EPA's decision to subcategorize major source biomass boilers by combustor type, but the Agency does not go far enough. Combustion distinctions exist within the stoker and fluidized bed designs which make further subcategorization into fixed, traveling, and rocker type stokers and bubbling and fluidized bed type combustors appropriate for combustion related (organic) HAPs. Precedence for subcategorizing to set CO limits is found in EPA's Large

Municipal Waste Combustor (MWC) MACT rule which subcategorizes MWCs into 13 different combustor types, including a distinction between bubbling and fluidized bed combustors. (71 FR 27335, Table 3). EPA should do likewise in the Major Boiler MACT rule.

Response: EPA disagrees that further subcategorization is justified. The commenter does not provide data or sufficient justification for further spllitting out the fluidized bed subcategory and without that data to support the argument EPA determined that this approach would create a very fractioned database.

Subcategories: Liquid

Commenter Name: Bob Machaver
Commenter Affiliation: Citizen
Document Control Number: EPA-HQ-OAR-2002-0058-0840.1
Comment Excerpt Number: 2

Comment: It does not seem appropriate to impose the same MACT PM emission standard for all types of oil, as No. 6 and No. 2 oil have very different ash content and fuel characteristics, and these differences are likely more pronounced for ultralow sulfur oils. The MACT analysis should be performed separately for the different major types of oil (i.e. No. 6 Oil, No. 2 Oil, UltraLow Sulfur Diesel Oil), and the resulting emission standards should be determined separately. All fuel oils should not all be lumped into a single classification and as a result be subject to the same emission standard.

Response: See response to comments EPA-HQ-OAR-2002-0058-2769.1, excerpt 3 , EPA-HQ-OAR-2002-0058-2960.1, excerpt 57 and EPA-HQ-OAR-2002-0058-2863.1, excerpt 22.

Commenter Name: Randolph Price
Commenter Affiliation: Consolidated Edison Company of New York
Document Control Number: EPA-HQ-OAR-2002-0058-1869.1
Comment Excerpt Number: 4

Comment: EPA should create two subcategories within the liquid-fueled emission sources and set separate MACT floor limits for each.

The Federal Register notice at page 32017 (second column) describes EPA's rationale for subcategorizing boilers and process heaters.

"We have identified the following 11 subcategories for organic HAP:
Pulverized coal units,
Stokers designed to burn coal,

Fluidized bed units designed to burn coal,
Stokers designed to burn biomass,
Fluidized bed units designed to burn biomass,
Suspension burners/Dutch Ovens designed to burn biomass,
Fuel Cells designed to burn biomass,
Units designed to burn liquid fuel,
Units designed to burn natural gas/refinery gas,
Units designed to burn other gases,
and Metal process furnaces.

These subcategories are based on the primary fuel that the boiler or process heater is designed to burn." [emphasis added]

The Federal Register notice, in the third column of the same page, also states:

"This would ensure that each boiler and process heater is subject to emissions standards calculated on the basis of the best performing units with similar design and operation."

Although there are three subcategories for coal units, four subcategories for biomass units, and three subcategories for gas-fired units (including metal process furnaces), there is only one category for all liquid-fired units. The emissions data published by EPA demonstrate that there are fundamental differences in the design, operation and emissions characteristics of residual oil-fired units and distillate oil-fired units such that two subcategories are warranted in the liquid-fired unit category. Only by creating two subcategories will EPA "ensure that each boiler . . . is subject to emission standards calculated on the basis of the best performing units with similar design and operation."

For example, Table 7 (CO Fuel by Floor) of Appendix C-2 of the April 2010 ERG Memorandum lists the units determining the MACT floor value for carbon monoxide (CO). Of the 14 units comprising the best-performing 12%, all burn distillate oil only (No. 2 distillate or jet fuel), except one unit -- and that one unit appears to represent an outlier value. [MACT Floor Analysis (2010) for Boilers an Process Heaters-Major Sources NESHAP] And in Table 2 (HCI Fuel by Floor) of Appendix C-2, the top-performing units burn a wide variety of fuels, including No. 4 oil, animal fats, vegetable oil, anhydrides waste liquids, No. 2 oil, blast furnace gas, and natural gas, with the greatest majority of the identified units burning a mixture of No. 2 distillate oil and aviation fuel. This same pattern is repeated in Table 3 (pM-Filter Fuel by Floor) of Appendix C-2 where none of the units identified in the top-performing 12% combust residual oil. Two units combust waste liquids, and all the remaining top performing units combust diesel fuel or No. 2 distillate fuel.

This failure to subcategorize liquid-fueled sources is of particular concern given that EPA subcategorized liquid fuels during the ICR process. For example, Table.2 in Section 2. 3 of the March 2010 ERG Memorandum, entitled "Categorical Fuel Material Hierarchy," lists a category for "heavy liquids" and "light liquids". Table B.I of the same document, entitled "Fuel Category Constituents," lists a variety of liquid fuels and wastes, once again divided in two categories -- "residual/heavy liquids" and "distillate/light liquids." The information contained in Part B of

Supporting Statement for ICR No. 2286.01, Appendix I -listing the 187 units tested as part of the ICR process - also divides the liquid-fueled units into "liquid (heavy)"and "liquid (light)" . Yet, EPA's proposed rulemaking provides no justification for discontinuing this differentiation between the two types of liquid fuel.

Just as stokers, fluidized bed units and Dutch ovens are configured differently, light oil and residual oil units are designed with different components. There are significant differences between the design for the combustion nozzles, flame temperatures, fuel forwarding pumps and controls, and fuel handling techniques of distillate-oil and residual-oil units. An entity specifically designing a boiler for each fuel would specify different tube surface area and spacing to accommodate the differences in heat and ash content between the two types of fuels.

To ensure that residual-oil units are treated consistently and in accordance with the stated intentions of the MACT process, EPA should re-establish a subcategory for residual-oil units and a subcategory for distillate-oil units, dividing the two subcategories in a manner consistent with Table B.I found in the March 2010 ERG Memorandum. Once these subcategories have been re-established, EPA should recalculate the MACT floor emission level for each subcategory of liquid-fueled units.

Response: EPA disagrees that residual oil-fired units require a separate subcategory. First, while EPA did request that units indicate whether they combust light or heavy liquid fuel in the ICR, this in no way impacts the final subcategories. Those decisions are made separately, regardless of the structure of the ICR. While there are design differences between light and heavy liquid units, the subcategories established by EPA, even for the various types of solid fuel-fired units of various designs, do not distinguish between designs for the fuel-based pollutants (Hg, PM, and HCl). That is, all solid fuel units are part of the same subcategory for the fuel based pollutants. While the subcategories have changed for coal and biomass units since proposal, the same general approach was followed at proposal. That is, all coal units had the same proposed limits for the fuel-based pollutants, and all biomass units had the same proposed limits for the fuel-based pollutants. Therefore, for the fuel based pollutants, covering all liquid fuel units within a single subcategory is consistent with the treatment of solid fuel units. For combustion-based pollutants (CO and dioxin/furan), the standards are based, in all cases, on a pool of best performers that included at least one-half residual oil units. Therefore, EPA is maintaining the same subcategorization approach for liquid fuel units.

Commenter Name: Richard T. Metcalf
Commenter Affiliation: Louisiana Mid-Continent Oil and Gas Association
Document Control Number: EPA-HQ-OAR-2002-0058-2699.1
Comment Excerpt Number: 7

Comment: Subcategorize the proposed liquids subcategory into light liquids and heavy liquids and apply work practice requirements to the clean-burning light liquids subcategory. Setting an emission limit based on distillate fuel oil emissions is not justifiable for the entire subcategory. Only a PM limit is warranted for the heavy oil subcategory.

Response: See response to comments EPA-HQ-OAR-2002-0058-2769.1, excerpt 3 , EPA-HQ-OAR-2002-0058-2960.1, excerpt 57 and EPA-HQ-OAR-2002-0058-2863.1, excerpt 22.

Commenter Name: Arthur N. Marin
Commenter Affiliation: NESCAUM
Document Control Number: EPA-HQ-OAR-2002-0058-2893.1
Comment Excerpt Number: 11

Comment: Elemental analyses of fuel oils recently conducted by NESCAUM indicate that emissions from #2 distillate oil are significantly lower in mercury and other trace metals than EPA's AP-42 emission factors would otherwise suggest. Trace metals were measured in various petroleum products sampled in the Northeast, including #6 residual fuel oil, #2 distillate oil, ultra-low sulfur heating oil, and bio-diesel. See submittal for Table 1 showing the trace metal results for #2 distillate oil and #6 residual oil, which are presented as input-based emission rates. Based on NESCAUM's fuel sampling work, the more refined petroleum products have a different composition and are lower in nickel (Ni) and vanadium (V) than the heavier #6 residual oil. The fuel sampling also found very low levels of mercury (Hg) in petroleum products, and underscored the need for EPA's National Emissions Inventory to be updated for several metals, including mercury, nickel, and vanadium. Furthermore, based on compliance data, when burned in a commercial or industrial boiler to produce heat, different blends of petroleum can have very different fine particle emission rates due to the combustion design of the heating system and the fuel composition.
See submittal for a bar chart of Figure 2 shows the particulate matter (PM) emission rates for different combustion systems and fuels used in heating equipment based on analysis conducted recently by the New York State Energy Research and Development Authority (NYSERDA). Currently, #2 distillate oil is the most common fuel for heating in the Northeast, after natural gas, and has a PM emission rate of approximately 0.008 lb/mmBtu. Ultra-low, or 15 ppm, sulfur heating oil has a PM emission rate of 0.000099 lb/mmBtu, about the same as the emissions rate for natural gas-fired boilers. Number 6 residual fuel oil is commonly used in large buildings and has PM emission rate twice that of a boiler burning #2 distillate oil.
Based on these data, NESCAUM believes that EPA can achieve its emission targets by regulating ultra-low sulfur #2 distillate oil with the same regulatory strategy EPA proposed for natural gas.

Response: See response to comments EPA-HQ-OAR-2002-0058-2769.1, excerpt 3 , EPA-HQ-OAR-2002-0058-2960.1, excerpt 57 and EPA-HQ-OAR-2002-0058-2863.1, excerpt 22.
Response to unique comment: EPA can achieve its emission targets by regulating ultra-low sulfur #2 distillate oil with the same regulatory strategy EPA proposed for natural gas

EPA disagrees with incorporating the same regulatory strategy as natural gas for units firing ultra-low sulfur #2 distillate oil. EPA did look at its database to determine if units firing ultra low sulfur fuel oil, based on a cutoff of 15 ppm (0.0015 wt. %) sulfur content specified by

NESCAUM. At this threshold there was not any standardized fuel analysis data for metallic HAP or Hg available to establish a separate MACT floor computation. EPA did have particulate matter data available for one test based on the firing of ultra low sulfur fuel oil, but the particulate matter results for this unit were much higher than the particulate matter resulting from the commenter's suggestions or the particulate matter data for natural gas.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 159

Comment: The liquid subcategory should be divided into light and heavy liquid subcategories. The light liquids would be those liquids with a 90% ASTM D-86 distillation of < 640 °F. This definition would split the liquids subcategory such that Number 2 fuel oil would be in the light liquids subcategory and heavier fuels would be in the heavy liquids subcategory. From the available data, there is a difference in emissions such as PM, but EPA's data is relatively limited, does not consider all operations, and suffers from many data quality issues. Based on a review of the top performing liquid boilers, however, those that are correctly categorized as liquid boilers are typically firing light liquids such as distillate oil (which is equivalent to home heating oil), which indicates a difference in emissions from heavy versus light liquid boilers. As not all boilers will be able to fuel switch due to fuel availability, EPA should gather additional data to support subcategorization of liquid boilers.

Residual fuel oils typically contain higher levels of ash and somewhat higher levels of metals See AP-42 factors for oil firing, Section 1.3.1. However, HAP metals content in residual fuel oil is strongly influenced by crude oil processed at a given refinery, because these metals volatilize only at very high temperatures and thus typically stay in the bottoms in crude units or in Vacuum units. Thus, the level of metals in a crude oil will be directly related to the metals in residual fuel oil. {citation} than do distillate fuel oils. The combination of these characteristics means that residual fuel oil-fired boilers and process heaters have higher emissions of metal HAPs and PM than boilers and process heaters burning distillate fuel oils (light liquid fuels).

Residual fuel oils also have significantly different firing properties than do distillate fuel oils. The combustion characteristics of light and heavy liquids are different, because these fuels have very different flow/viscosity and atomization characteristics and different energy contents. Per API, typical residual fuel has about 7% more energy per gallon than a distillate fuel oil. As a result of these property differences, at a minimum, heavy fuel oil firing requires different burner tips then are needed when firing lighter fuel oils. The heating value and flame height differences between these fuels may also impose unit design and operating constraints.

In addition, residual fuel-fired boilers must operate a soot blowing cycle on a periodic basis to maintain their heat transfer efficiency, during which opacity and PM levels increase. While the liquids database does not appear to include any data characterizing soot blowing emissions, the proposed emission limits would apply during that time and thus these emissions must be considered. It is, therefore, clear that metal HAP and PM emissions at least, distinguish residual fuel-fired units from distillate-fired units. Indeed, EPA has recognized this fact by creating an implicit subcategory for residual-fuel fired units in the proposal by requiring in § 63.7525 that residual oil-fired process heaters and boilers (but not distillate units) install a PM CEMS. Thus, from an equipment design and operations standpoint as well as an emissions standpoint, there is a clear distinction between boilers and process heaters firing light liquids versus those that fire heavy liquids. By splitting the liquid subcategory and applying work practice requirements to the new light liquids subcategory (as most emissions from these units are so low that they cannot be reliably measured), the Agency would incentivize sources to switch to light liquids, where they can.

Response: Data for the best performing units in the subcategory show that the units achieved the levels of emissions upon which the floors are based. While units blowing soot were not identified as best performers, emission controls can be installed to meet the floor levels, or sources may choose to change their fuel mix to comply with the standards. For additional information see the response to the following comment, DCN: EPA-HQ-OAR-2002-0058-1869.1, except 4.

Commenter Name: Leonard W. Sandridge
Commenter Affiliation: University of Virginia
Document Control Number: EPA-HQ-OAR-2002-0058-2769.1
Comment Excerpt Number: 3

Comment: UVA believes EPA should reconsider the decision to place all liquid-fired fuels into one subcategory. In fact, early EPA technical documentation appears to indicate that two subcategories of liquid fuels were considered (see ERG "Baseline Emission Factor" memo Docket #EPAHQ-OAR-2002-0058-0802) but only one liquid fuel subcategory appears in the proposed rule.

Liquid fuels, by regulatory definition, include distillate oil, residual oil, on-spec used oil, and biodiesel. The oils may vary from ultralow sulfur diesel (ULSD) to #6, with likely varying concentrations of ash, chlorine, and mercury. The table below provides heating values and densities for several of these fuels.

[See submittal for table of Fuel Oil Heating Values]

Heating Value (Btu/gal) & Density (lb/ft3) Source: www.engineeringtoolbox.com

Maximum Ash Content Source: Colonial Pipeline Specifications and 2003 ASTM book: Fuels and Lubricants Handbook: Technology, Properties, Performance.

With typical heating values and densities, and assuming all constituents in the fuel are emitted (a realistic scenario for many liquid fuel fired units without air pollution control devices), it is possible to convert the emission limits into fuel concentrations. The proposed PM emission limit of 0.004 lb/MMBTU is equal to approximately 0.008% ash in the fuel. This is below the specification for maximum ash content in these fuels. Therefore, if the fuels barely meet the specifications and burn without any soot formation, ash in the fuel will still lead to PM emissions exceeding the limit, without some type of control device. Distillate oils may be able to meet the PM limits without controls, while heavier fuels will likely need to install PM controls.

Response: EPA disagrees that further subcategorization by type of liquid fuel is warranted. EPA may not subcategorize on the basis of emissions of the unit, so although the particulate matter or HAP emitted from distillate vs. residual fuel oil may vary this is not a valid reason for subcategorizing. EPA maintained separate baseline emission factors for light vs. heavy liquids in order to more accurately estimate the baseline emissions and emission reductions of the standard but this baseline emission analysis does not imply that the liquid fuel category should be separated.

Commenter Name: Henry T. Graham
Commenter Affiliation: Louisiana Chemical Association
Document Control Number: EPA-HQ-OAR-2002-0058-2731.1
Comment Excerpt Number: 7

Comment: Subcategorize the proposed liquids subcategory into light liquids and heavy liquids and apply work practice requirements to the clean-burning light liquids subcategory. Setting an emission limit based on distillate fuel oil emissions is not justifiable for the entire subcategory. Only a PM limit is warranted for the heavy oil subcategory.

Response: See response to comments EPA-HQ-OAR-2002-0058-2769.1, excerpt 3 , EPA-HQ-OAR-2002-0058-2960.1, excerpt 57 and EPA-HQ-OAR-2002-0058-2863.1, excerpt 22.

Commenter Name: William R. Ermatinger
Commenter Affiliation: Northrop Grumman
Document Control Number: EPA-HQ-OAR-2002-0058-2506.1
Comment Excerpt Number: 29

Comment: It is inappropriate to include residual oil-fired steam boilers, distillate oil-fired steam boilers, other liquid fuel-fired steam boilers and liquid fuel-fired process heaters in the same subcategory, and it is erroneous to establish a single set of emission limits that apply to all such units in the subcategory. Separate subcategories should be established for boilers and process heaters based on specific fuels utilized, type of combustion unit, heat input rating, and nature of the use or application of a boiler, and separate emission limits and work practice standards should be established for each such subcategory based on valid field testing data.

Steam boilers and process heaters are fundamentally different pieces of equipment having different designs, functions, purposes, operating characteristics and emissions. Even within the grouping of liquid fuel-fired steam boilers, there is a wide variation in equipment design, sizes, applications, operating characteristics, fuel types and emissions. It is not reasonable to expect that all units in this category, as defined by EPA, would be capable of meeting a "one size fits all" set of emission limitations and work practice standards. At a minimum, separate subcategories should be established for boilers and for process heaters, and each of those subcategories should be further subdivided by size range, fuel type and the other differentiating factors mentioned above. An existing example demonstrating the feasibility of such subdivision or source types can be found in EPA's new source performance standards (NSPS) for fossil fuel-fired steam generating units, found at 40 CFR Parts D, Da. Db and Dc.

Response: While the commenter cites several reasons why separate subcategories might be warranted for liquid fuel-fired combustion units, and states that a single subcategory is not reasonable, the commenter provided little support for the conclusions provided. For additional information see the responses to the following comments, DCN: EPA-HQ-OAR-2002-0058-3213.1, excerpt 159 and DCN: EPA-HQ-OAR-2002-0058-1869.1, excerpt 4.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-2702.1
Comment Excerpt Number: 55

Comment: CIBO also supports EPA subcategorizing for light versus heavy liquid fuels. There are strong technical arguments why EPA should split the liquids into separate sub-categories and not the gases. Fuel gases don't vary much in HAP content with the possible exception of mercury. Liquid fuel HAP contents are likely to vary a good bit with the main division being light (DO) versus heavy (RO).

Response: See response to comments EPA-HQ-OAR-2002-0058-2769.1, excerpt 3 , EPA-HQ-OAR-2002-0058-2960.1, excerpt 57 and EPA-HQ-OAR-2002-0058-2863.1, excerpt 22.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 57

Comment: The liquids subcategory should be divided into light and heavy liquids subcategories. The light liquids would be those liquids with a 90% ASTM D-86 distillation of < 640 degree F. This definition would split the liquids subcategory such that Number 2 fuel oil would be in the light liquids subcategory and heavier fuels would be in the heavy liquids subcategory. From the available data, there are differences in sulfur and PM emissions that make such a split necessary. EPA's data and the proposed emission limits indicate little difference in HAP emissions between liquids and gases, but the EPA data is relatively limited, does not consider all operations and suffers from many of the same data quality issues discussed for gas-fired units. The differences between light and heavy liquid combustion are generally recognized. For instance, Northeast States for Coordinated Air Use Management (NESCAUM) concluded the following for light liquids reducing the sulfur content of heating oil from 2,500 ppm to 500 ppm lowers SO2 emissions by 75 percent, PM emissions by 80 percent, NOx emissions by 10 percent, and CO_2 emissions by 1 to 2 percent. Other benefits associated with lowering the sulfur content of heating oil include heating system efficiency improvements,..." [Footnote: NESCAUM, Low Sulfur Heating Oil in the Northeast States: An Overview of Benefits, Costs and Implementation Issues, December 2005 (included in Attachment I to these comments)] For all the same reasons applicable to Gas 1 fuels, only work practice standards are feasible to measure and enforce for light liquids or for all but PM for heavy liquids.

Response: EPA disagrees that further subcategorization by type of liquid fuel is warranted. EPA may not subcategorize on the basis of emissions of the unit, so although the HAP emitted from distillate vs. residual fuel oil may vary this is not a valid reason for subcategorizing. Units firing distillate fuel are still included in the liquid subcategory. As such they are subject to the emission limits that are applicable to liquid fuel fired units. However, we do recognize that emissions from firing distillate oil are lower than from firing residual oil, and reflect this in the rule. Units firing distillate oil may demonstrate compliance with fuel analysis in lieu of a stack test to reduce compliance burden.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 59

Comment: Residual fuel oils also have significantly different firing properties than do distillate fuel oils. The combustion characteristics of light and heavy liquids are different, because these fuels have very different flow/viscosity and atomization characteristics and different energy contents. Typically, residual fuel has about 7% more energy per gallon than a Number 2 fuel oil. As a result of these property differences, at a minimum, heavy fuel oil firing requires different burner tips than are needed when firing lighter fuel oils. The heating value and flame height differences between these fuels may also impose unit design and operating constraints.

Response: See response to comments EPA-HQ-OAR-2002-0058-1869.1, excerpt 4 and EPA-HQ-OAR-2002-0058-3213.1, excerpt 159.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1

Comment Excerpt Number: 60

Comment: Residual fuel-fired boilers must operate a soot blowing cycle on a periodic basis to maintain their heat transfer efficiency, during which opacity and PM levels increase. While the liquids database does not appear to include any data characterizing soot blowing emissions, the proposed emission limits would apply during that time and thus these emissions must be considered. It is, therefore, clear that metal HAP and PM emissions at least, distinguish residual fuel-fired units from distillate-fired units. Indeed, EPA has recognized this fact by creating an implicit subcategory for residual-fuel fired units in the proposal by requiring in 63.7525 that residual oil-fired process heaters and boilers (but not distillate units) with greater than 250 MMBTU/hr design heat input install a PM CEMS.

Thus, from an equipment design and operations standpoint as well as an emissions standpoint, there is a clear distinction between boilers and process heaters firing light liquids versus those that fire heavy liquids. By splitting the liquid subcategory and applying work practice requirements to the new light liquids subcategory, the Agency would incentivize sources to switch to light liquids, where they can.

Recommendation: Split the proposed liquid subcategory into a light liquid and heavy liquid subcategory and apply work practice requirements, except possibly for PM in the heavy liquids subcategory.

Response: See response to comments EPA-HQ-OAR-2002-0058-1869.1, excerpt 4 and EPA-HQ-OAR-2002-0058-3213.1, excerpt 159.

Commenter Name: Debra J. Jezouit
Commenter Affiliation: Class of '85 Regulatory Response Group
Document Control Number: EPA-HQ-OAR-2002-0058-2802.1
Comment Excerpt Number: 10

Comment: The Group believes that EPA should consider allowing sources to comply with the proposed emissions standards by using ultra-low sulfur diesel fuel exclusively. EPA is proposing annual and monthly recordkeeping and reporting requirements that would be sufficient for units that opt to use ultra-low sulfur diesel to demonstrate continuous compliance with the proposed emissions standards.

Response: See response to comments EPA-HQ-OAR-2002-0058-2769.1, excerpt 3 , EPA-HQ-OAR-2002-0058-2960.1, excerpt 57 and EPA-HQ-OAR-2002-0058-2863.1, excerpt 22.

Commenter Name: Debra J. Jezouit
Commenter Affiliation: Class of '85 Regulatory Response Group
Document Control Number: EPA-HQ-OAR-2002-0058-2802.1

Comment Excerpt Number: 12

Comment: Proposed 63.7575 includes biodiesel in the definition of "Liquid Fuel." Please clarify whether liquid biofuels such as crude palm oil and other crude biofuels and algal fuel are considered "Liquid Fuel" under the Proposed Rule.

Response: Biodiesel is an example of a liquid fuel, any fuel that is in a liquid state of matter and is not determined to be a waste material is included in the definition of liquid fuel.

Commenter Name: James C. Jackson
Commenter Affiliation: Boise, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2855.1
Comment Excerpt Number: 1

Comment: Boise has a total of nineteen boilers located at its five mills which would be subject to the proposed Boiler MACT rule. Nine of these boilers are capable of burning only natural gas and would be subject to the rule's "Gas 1" subcategory annual tune-up requirements. Five additional boilers are capable of burning a combination of natural gas and fuel oil and, as currently operated, would be subject to the "units designed to burn liquid fuel" subcategory. However, given the significant cost to install controls on these boilers to meet the limits for liquid fuel boilers, it is likely that their capability to burn fuel oil would be limited. as outlined in the rule, so that they would also be Gas 1 subcategory boilers; in which case, they would also be subject to the annual tune-up requirement.

Response: EPA has adjusted the subcategory definitions to be based on actual fuel usage.

Commenter Name: Gordon M. Smith
Commenter Affiliation: Mitsubishi Polyester Film, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2912
Comment Excerpt Number: 1

Comment: The liquids subcategory should be divided into light liquids (distillate oil) and heavy liquids (residual oil) subcategories, following the proposed definitions in §63.7575. EPA's data and the proposed emission limits indicate little difference in HAP emissions between liquids and gases, but the EPA data is relatively limited and does not consider all operations.
Residual fuel oils (heavy liquid fuels) typically contain higher levels of ash and somewhat higher levels of metals[See AP-42 factors for oil firing, Section 1.3.1.] than do distillate fuel oils. The combination of these characteristics means that residual fuel oil-fired boilers and process heaters have higher emissions of metal HAPs and PM than boilers and process heaters burning distillate fuel oils (light liquid fuels).
Residual fuel oils also have significantly different firing properties than do distillate fuel oils. The combustion characteristics of light and heavy liquids are different, because these fuels have

very different flow/viscosity and atomization characteristics and different energy contents. Typically, residual fuel has about 7% more energy per gallon than a Number 2 fuel oil. As a result of these property differences, at a minimum, heavy fuel oil firing requires different burner tips then are needed when firing lighter fuel oils. The heating value and flame height differences between these fuels may also impose unit design and operating constraints.
In addition, residual fuel-fired boilers must operate a soot blowing cycle on a periodic basis to maintain their heat transfer efficiency, during which opacity and PM levels increase. While the liquids database does not appear to include any data characterizing soot blowing emissions, the proposed emission limits would apply during that time and thus these emissions must be considered. It is, therefore, clear that metal HAP and PM emissions at least, distinguish residual fuel-fired units from distillate-fired units. Indeed, EPA has recognized this fact by creating an implicit subcategory for residual-fuel fired units in the proposal by requiring in §63.7525 that residual oil-fired process heaters and boilers (but not distillate units) having heat input capacities greater than 250 MMBtu per hour install a PM CEMS.
Thus, from an equipment design and operations standpoint as well as an emissions standpoint, there is a clear distinction between boilers and process heaters firing light liquids versus those that fire heavy liquids.

Response: See response to comments EPA-HQ-OAR-2002-0058-1869.1, excerpt 4 and EPA-HQ-OAR-2002-0058-3213.1, excerpt 159.

Commenter Name: David W. Peightal
Commenter Affiliation: Dakota Gasification Company
Document Control Number: EPA-HQ-OAR-2002-0058-3179
Comment Excerpt Number: 2

Comment: DGC proposes a heavy liquid fuel subcategory. In 75 FR32017 (June 4, 2010), EPA discusses reasons for incorporating subcategories into the proposed rule where it states, "Therefore, because different types of units have different emission characteristics which may influence the feasibility of effectiveness of emission control, they should be regulated separately (i.e., subcategorized)." DGC agrees with this statement and therefore proposes a heavy liquid fuel subcategory. The uniqueness of our liquid fuels (all are lignite derived) and their unclassified nature in the current rule proposal begs for a separate subcategory. The liquid fuels combusted include tar oil, naphtha, and crude phenol which are all recovered via the gasification process. The standards as proposed for existing liquid-fired boilers are not technically achievable for our facility configuration.

Response: EPA disagrees that further subcategorization of liquid fuels is warranted. The commenter did not provide sufficient data or technical justfication for a separate subcategory for these fuel types.

Commenter Name: William O'Sullivan

Commenter Affiliation: New Jersey Department of Environmental Protection
Document Control Number: EPA-HQ-OAR-2002-0058-2969.1
Comment Excerpt Number: 5

Comment: We recommend there be different emission standards for the Tight oil-fired (distillate oil)
units and heavy oil-fired (residual) units to account for differences in these oils. Number 2 oil should be treated like natural gas, especially where the sulfur requirement is 15 ppm.

Response: See response to comments EPA-HQ-OAR-2002-0058-2769.1, excerpt 3 , EPA-HQ-OAR-2002-0058-2960.1, excerpt 57 and EPA-HQ-OAR-2002-0058-2863.1, excerpt 22.

Commenter Name: Daniel Moss
Commenter Affiliation: Society of Chemical Manufacturers and Affiliates
Document Control Number: EPA-HQ-OAR-2002-0058-2926.1
Comment Excerpt Number: 8

Comment: If EPA retains an exception to the oil-fired boiler subcategory for units that burn liquid fuels for specific purposes, SOCMA recommends that the EPA limit the 48-hour cap to periodic testing, as EPA did in the Area Source Boiler proposal; and - Dispense with the 48 hour declaration notification requirement.

Response: EPA has adjusted exception in the final rule to limit the 48-hour cap to periodic testing. This 48-hour period now excludes time when the unit fired liquid due to curtailment or supply emergencies.

Commenter Name: Michael Hutcheson
Commenter Affiliation: Ameren Services
Document Control Number: EPA-HQ-OAR-2002-0058-2803.1
Comment Excerpt Number: 15

Comment: Ameren believes US EPA should separate the liquid fueled subcategory into heavy and light distillate fuels and another subcategory for other.

Response: See response to comments EPA-HQ-OAR-2002-0058-2769.1, excerpt 3 , EPA-HQ-OAR-2002-0058-2960.1, excerpt 57 and EPA-HQ-OAR-2002-0058-2863.1, excerpt 22.

Commenter Name: Christopher S. Colman
Commenter Affiliation: Hovensa LLC
Document Control Number: EPA-HQ-OAR-2002-0058-2863.1

Comment Excerpt Number: 20

Comment: In addition, residual fuel fired boilers operate a soot blowing cycle on a periodic basis, typically daily, during which opacity and PM levels are increased significantly for a duration of up to 2 hours at some units at HOVENSA. Soot blowing is required to maintain the energy efficiency of the boiler. Indeed, EPA has recognized the higher PM emissions from residual fuel oil by creating an implicit subcategory for residual fuel by requiring in § 63.7525 that residual fuel fired heaters and boilers (but not distillate units) install a PM CEMS. The preamble indicates that residual fuel oil is also subject to a 10% opacity limit, but it is less clear how the rule proposes to implement the statement in the preamble.16 Soot blowing adds to the significant operation differences between residual and distillate fuel oils as regards particulate matter emissions.
[Footnote 15: Soot blowing is a standard industry practice for residual fuel oil fired equipment. Soot blowing maintains the fuel efficiency of the equipment by periodically cleaning the heater tubes. If soot blowing is not performed, the amount of fuel combusted increases substantially because heat transfer is impeded across the boiler tubes, so that more energy is required to make steam or heat the product. A more commonplace example of this is the need to clean air conditioning units, so that heat transfer is not impeded.]
[Footnote 16: HOVENSA specifically requests that EPA address this point more clearly in any final rule, and that residual fuel oil be exempted from this standard and the PM standard during soot blowing.]

Response: See response to comments EPA-HQ-OAR-2002-0058-1869.1, excerpt 4 and EPA-HQ-OAR-2002-0058-3213.1, excerpt 159.

Commenter Name: Christopher S. Colman
Commenter Affiliation: Hovensa LLC
Document Control Number: EPA-HQ-OAR-2002-0058-2863.1
Comment Excerpt Number: 21

Comment: As EPA noted, fuel switching does not necessarily result in lower HAP emissions of all HAPs, which is the case for residual fuel oil combustion vs. distillate. For example, mercury in residual fuel oil is typically as low as (or lower) than in distillate fuel oil or even some gases for the converse reason that heavy metals concentrate in residual fuel oil. Likewise, the True Vapor Pressure of residual fuel oil is extremely low and, as a corollary, so is the volatile organics content of this fuel.17 18 Table 7-1-2 of the AP-42 emissions factor handbook reports that No. 6 fuel oil has a TVP of .00006 psi at 70oF vs. .009 for distillate fuel oil and 8 or more for gasoline. In view of the fact that combustion efficiency of residual fired heaters and boilers should be equivalent to distillate or gas fired units, emissions of volatile organic HAPs should be very similar to or (more likely) lower than distillate fuels.19
Residual fuel oil has significantly different firing properties than does distillate fuel oil or natural gas. As EPA correctly observed in the preamble, a burner cannot fire a different fuel without being retrofitted. A switch to a different fuel requires significant changes to the burner and can also require changes to the firebox to optimize combustion. 20 A firebox modification requires

very substantial rebuilds to the heater or boiler and is not practicable for most sources. The combustion characteristics change is less dramatic between residual fuel oils and distillate fuels, but is still significant because distillate and residual fuels have very different flow/viscosity and atomization characteristics and different energy contents. Typically, residual fuel has about 7% more energy per gallon than a No. 2 Oil. At a minimum, residual fuel oil requires different burner tips because of the physical differences between residual and distillate fuels. The heating value and flame height differences between these fuels may impose unit design constraints.
We also note that the residual fuel oil is more abrasive than distillate fuels. The effect of this is that the holes in the burner tips on residual fuel oil burners will wear more quickly than those in other services.
This results in less effective atomization of the residual fuel oil as the holes slightly enlarge. Residual fuel oil also tends to plug burner tips more frequently, again resulting in improper atomization and higher CO emissions. Nothing in the EPA database captures this kind of longer term degradation in performance for residual fuel oil burning performance.

[Footnote 17: "Volatility is indicated by a substance's vapor pressure. It is a tendency of a substance to vaporize or the speed at which it vaporizes. Substances with higher vapor pressure will vaporize more readily at a given temperature than substances with lower vapor pressure." http://www.epa.gov/iaq/voc2.html]
[Footnote 18: EPA used VOC as a surrogate in evaluating the emissions benefits of this rule for organic HAPS. We note that the methane is not defined as a VOC, so that it is difficult to compare gas and fuel oil in this context. However, Table 10 of the preamble shows very small VOC emissions decreases from the impact of this rule, confirming the relatively low VOC (as defined) content of residual fuel oil.]
[Footnote 19: We note that in effect forcing a switch to distillate fuel oil from residual fuel oil results in environmental "collateral damage." Distillate fuel oil production is more energy intensive and combustion emissions are higher. CO_2 is also very significant increased because of the need to hydrotreat distillates to lower sulfur levels. This is largely because the process to make hydrogen splits hydrogen from a hydrocarbon, resulting in CO_2 emissions.]
[Footnote 20: Flame heights differ between fuels. Combustion is optimized when the flame height is about 2/3rds of the firebox height. Any change in fuel will change the optimal combustion design of the firebox.]

Response: See response to comments EPA-HQ-OAR-2002-0058-1869.1, excerpt 4 and EPA-HQ-OAR-2002-0058-3213.1, excerpt 159.

Commenter Name: Christopher S. Colman
Commenter Affiliation: Hovensa LLC
Document Control Number: EPA-HQ-OAR-2002-0058-2863.1
Comment Excerpt Number: 22

Comment: Residual fuel oil is significantly lower in cost that distillate fuel and, as noted above, does not necessarily result in a higher level of all HAP emissions. Demand for light distillate fuels has risen significantly worldwide, while demand for residual fuel oils has fallen. The effect

is that the cost of distillate fuels is significantly higher than residual fuels—ranging between 20 and 40 dollars per barrel over the last 5 years, adjusted for the approximately 7% higher energy content of residual fuel oil. (See submittal for cost differential figure 4)
The differentials have narrowed since 2008 but remain in the vicinity of $20/bbl.
The cost differential between distillate and residual fuel oil is extremely significant to the facilities that combust these fuels. For example, a facility combusting 1MM barrels of residual fuel oil per year will have added fuel costs of 20 to 30 million dollars annually to burn distillate fuel—costs which are not faced by facilities with access to natural gas. By lumping distillate and residual fuel oil combustors together in setting MACT floors, despite their very significant differences in emissions characteristics of the fuels, EPA is effectively setting a standard that requires a fuel switch, despite extensive language in the preamble disclaiming this intent. Forcing a switch to distillate fuels, in combination with the control costs that this rule imposes, will cripple or close these facilities that rely on residual fuel oil combustion.
[Footnote 22: "For the reasons discussed above, we decided that fuel switching to cleaner solid fuels or to liquid or gaseous fuels is not an appropriate criteria for identifying the MACT floor emission levels for units in the boilers and process heaters category." 75 FR at 30219.]

Response: EPA may not consider cost impacts when establishing the floor. EPA disagrees that further subcategorization by liquid fuel type is warranted. As the commenter suggests the decision to purchase residual fuel oil is based on cost and EPA may not subcategorize by cost. No technical design differences between units designed to burn distillate vs. residual fuels were noted to provide the basis for further subcategorization.

Commenter Name: Michael Hutcheson
Commenter Affiliation: Ameren Services
Document Control Number: EPA-HQ-OAR-2002-0058-2803.1
Comment Excerpt Number: 27

Comment: US EPA should divide the liquid fuel subcategory into petroleum based fuels and byproduct based fuels.

The only detectable Hg in stack test data used for liquid MACT floor development came from sources burning non-petroleum fuels (bio-fuels and BFG). The only exception was the Consolidated Edison Boiler 118 in New York which is reported as having a Fabric Filter and sorbent injection but still showing detectable levels of Hg post control. As such the test data for this source is suspect. Ameren believes US EPA should revise the liquid fuel source category to distinguish between petroleum based sources and by-product fuels used at individual facilities.

Response: See response to comment EPA-HQ-OAR-2002-0058-3179, excerpt 2.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council

Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 79

Comment: The liquid subcategory should be divided into light and heavy liquid subcategories. The light liquids would be those liquids with a 90% ASTM D-86 distillation of < 640 °F. This definition would split the liquids subcategory such that Number 2 fuel oil would be in the light liquids subcategory and heavier fuels would be in the heavy liquids subcategory. From the available data, there is a difference in emissions such as PM, but EPA's data is relatively limited, does not consider all operations, and suffers from many data quality issues. Based on a review of the top performing liquid boilers, however, those that are correctly categorized as liquid boilers are typically firing light liquids such as distillate oil (which is equivalent to home heating oil), which indicates a difference in emissions from heavy versus light liquid boilers. As not all boilers will be able to fuel switch due to fuel availability, EPA should gather additional data to support subcategorization of liquid boilers.

Residual fuel oils typically contain higher levels of ash and somewhat higher levels of metals [See AP-42 factors for oil firing, Section 1.3.1. However, HAP metals content in residual fuel oil is strongly influenced by crude oil processed at a given refinery, because these metals volatilize only at very high temperatures and thus typically stay in the bottoms in crude units or in Vacuum units. Thus, the level of metals in a crude oil will be directly related to the metals in residual fuel oil. AP-42, Volume I, Fifth Edition, Section 1.3.1, http://www.epa.gov/ttn/chief/ap42/] than do distillate fuel oils. The combination of these characteristics means that residual fuel oil-fired boilers and process heaters have higher emissions of metal HAPs and PM than boilers and process heaters burning distillate fuel oils (light liquid fuels).

Residual fuel oils also have significantly different firing properties than do distillate fuel oils. The combustion characteristics of light and heavy liquids are different, because these fuels have very different flow/viscosity and atomization characteristics and different energy contents. Per API, typical residual fuel has about 7% more energy per gallon than a distillate fuel oil. As a result of these property differences, at a minimum, heavy fuel oil firing requires different burner tips then are needed when firing lighter fuel oils. The heating value and flame height differences between these fuels may also impose unit design and operating constraints.

In addition, residual fuel-fired boilers must operate a soot blowing cycle on a periodic basis to maintain their heat transfer efficiency, during which opacity and PM levels increase. While the liquids database does not appear to include any data characterizing soot blowing emissions, the proposed emission limits would apply during that time and thus these emissions must be considered. It is, therefore, clear that metal HAP and PM emissions at least, distinguish residual fuel-fired units from distillate-fired units. Indeed, EPA has recognized this fact by creating an implicit subcategory for residual-fuel fired units in the proposal by requiring in section 63.7525 that residual oil-fired process heaters and boilers (but not distillate units) install a PM CEMS.

Thus, from an equipment design and operations standpoint as well as an emissions standpoint, there is a clear distinction between boilers and process heaters firing light liquids versus those that fire heavy liquids. By splitting the liquid subcategory and applying work practice requirements to the new light liquids subcategory (as most emissions from these units are so low that they cannot be reliably measured), the Agency would provide incentives for sources to switch to light liquids where appropriate.

Response: See response to comments EPA-HQ-OAR-2002-0058-1869.1, excerpt 4 and EPA-HQ-OAR-2002-0058-3213.1, excerpt 159.

Subcategories: Natural Gas/Refinery Gas (Gas 1)

Commenter Name: William C. Herz
Commenter Affiliation: The Fertilizer Institute
Document Control Number: EPA-HQ-OAR-2002-0058-1910.1
Comment Excerpt Number: 3

Comment: TFI offers that, because emission limits are proposed in units of pounds per million British thermal units, there is no need to delineate subcategories of natural gas-fired boilers and process heater units. The same work practice standard that is proposed for the Gas 1 subcategory is equally effective for all natural gas-fired boilers and process heater units, regardless of heat input capacity. Heat input capacity does not significantly change the operation of boilers and process heater units, nor is there a difference in the characteristics of the natural gas used in these units. Further, the proposed rule does not provide any compliance and monitoring requirements for those natural gas-fired boilers and process heater units with heat input capacity between 10 and 100 MMBtu/h.
TFI requests that EPA require all natural gas-fired boilers and process heater units adhere to the same work practice standard. If EPA determines that it will not subject all natural gas-fired boilers and process heater units to the same work practice standard, TFI requests that the Agency redefine the Gas 1 subcategory to include all natural gas-fired boilers and process heater units having a heat input capacity less than 100 MMBtu/h.

Response: EPA acknowledges the comment and agrees that separate standards are unecessary for gas-fired boilers versus process heaters.

Commenter Name: N/A
Commenter Affiliation: Sierra Club, Clean Air Task Force, Earthjustice, and Natural Resources Defense Council
Document Control Number: EPA-HQ-OAR-2002-0058-3187.1
Comment Excerpt Number: 2

Comment: EPA justifies its subcategories for boilers burning at least 90 percent natural gas/refinery gas, and for metal process heaters essentially on cost and policy grounds, neither of which is a lawful basis for setting subcategories under section 112(d). It is notable, at the outset, that these subcategories include over 11,000 of the 13,555 boilers EPA identifies as the universe of regulated major source industrial boilers. For these boilers and process heaters, EPA first states that setting separate subcategories would assure that they are subject to emissions standards on the basis of their emissions characteristics. 75 Fed. Reg. 32,017. The natural gas/refinery gas subcategory, the Agency asserts, is necessary to ensure standards based on "the best performing units with similar design and operation," id., even though what the Agency actually does is to propose a work process standard for this subcategory (which as shown below is further unlawfully supported entirely on the policy grounds that it will incent fuel-switching to gas).

Response: EPA has revised the definition of natural gas, consistent with the boiler NSPS definition. Any other gaseous fuels other than natural gas or refinery gas must demonstrate that they are at or below the specifications in the final rule for mercury and hydrogen sulfide. See preamble for discussion of gas specification. The 48-hour allowance or period of gas curtailment/gas supply emergencies applies to any liquid fuel, so any gas 1 boiler firing compareable liquid fuels for periodic testing or during allowable periods could still qualify as a gas 1 boiler.

Commenter Name: Stephen R. Gossett
Commenter Affiliation: Eastman Chemical Company
Document Control Number: EPA-HQ-OAR-2002-0058-3137.1
Comment Excerpt Number: 30

Comment: EPA should expand the Gas 1 subcategory to also include other gases that, like natural gas and refinery gas (we also note that there is no definition for refinery gas in the proposed rule), are expected to contain little to no "fuel dependent HAP" such as mercury, heavy metals, and chlorine. For example, process gases generated by chemical manufacturing processes would be similar to refinery gases. Eastman has several such process gas streams which we believe pose no different issues than natural gas or refinery gas when combusted. These gas streams are all different mixtures of hydrogen, nitrogen, carbon dioxide, carbon monoxide and a variety of hydrocarbons including methane, ethane, ethylene, and propane. Chlorine is not expected in any of these streams over 5 ppmv and no heavy metals are known to be present. The lowest heating value of these streams is 325 Btu/scf and several of the streams contain significant amounts of hydrogen. These streams are all burned in highly efficient combustion devices.

Response: We appreciate the input from the commenter. We are not finalizing limits for units firing natural gas, refinery gas, and other Gas 1 fuels. See preamble for rationale for selecting a work practice for these units.

Commenter Name: Stephen R. Gossett
Commenter Affiliation: Eastman Chemical Company
Document Control Number: EPA-HQ-OAR-2002-0058-3137.1

Comment Excerpt Number: 31

Comment: If EPA is concerned that some process gases are of lower value and may not burn well, we suggest that EPA set some thresholds for heating value and/or hydrogen content similar to what was done for the NSPS flare criteria (see 40 CFR 60.18(b)). Here, gases burned in non-assisted flares must have either a minimum hydrogen content of 8 percent or a minimum heating value of 200 Btu/scf.

Response: We appreciate the input from the commenter. We are not finalizing limits for units firing natural gas, refinery gas, and other Gas 1 fuels. See preamble for rationale for selecting a work practice for these units.

Commenter Name: Britt S. Fleming
Commenter Affiliation: Auto Group
Document Control Number: EPA-HQ-OAR-2002-0058-2775.1
Comment Excerpt Number: 56

Comment: Given the importance of landfill gas and the fact that landfill gas can be processed to the extent that it is like natural gas (and even injected into natural gas pipelines), the Auto Group recommends that EPA add a component to the definition of “natural gas” that would include landfill gas, i.e., a fourth component to the definition that would say “any landfill gas that is processed and transported through a dedicated pipeline.” “Landfill gas” also could be defined as “gas derived from the decomposition of waste in a landfill.” [Footnote: See BAAQMD, Regulation 9, Rule 7.] This would ensure that landfill gas units are treated similarly to natural gas units given these fuels can be found in the same distribution system.

Response: See response to comments EPA-HQ-OAR-2002-0058-2761.1, excerpt 15 and EPA-HQ-OAR-2002-0058-2702.1, excerpt 73 for the definition of natural gas needs to be broader to account for non-geological origins of natural gas.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 167

Comment: It is not possible for EPA to subcategorize further on the basis of design characteristics and then apply the floor methodologies in section 112(d)(3) to derive numerical emission limits for each appropriate subgrouping of Gas 1 units. The Gas 1 database lacks sufficient information on design characteristics to allow rational sub-grouping of all of the Gas 1 units. In addition, the database lacks sufficiently robust emissions data to allow the calculation of floors for each of the resulting subgroups. As we have discussed elsewhere, we do not feel the database information is even adequate for allowing emission limits to be calculated for the subcategories recommended in the proposal, much less for subcategories of those subcategories.

Response: See response to comment EPA-HQ-OAR-2002-0058-2690.1, excerpt 41 for dataset inadequacies.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 172

Comment: The characteristics of refinery gas and other gases such as petrochemical gas are extremely similar, which supports the inclusion of petrochemical gas into the Gas 1 category with natural gas and refinery fuel gas. These gases are clean burning fuels and are composed mainly of methane, ethane, and hydrogen.

Response: We appreciate the input from the commenter. We are not finalizing limits for units firing natural gas, refinery gas, and other Gas 1 fuels. See preamble for rationale for selecting a work practice for these units.

Commenter Name: Stephen R. Gossett
Commenter Affiliation: Eastman Chemical Company
Document Control Number: EPA-HQ-OAR-2002-0058-3137.1
Comment Excerpt Number: 32

Comment: To our knowledge, it does not appear that EPA has gathered information to justify placing chemical process gases in a separate subcategory from natural gas and refinery gas. Information on composition and heating value was not requested in the Phase I ICR survey.

Response: We appreciate the input from the commenter. We are not finalizing limits for units firing natural gas, refinery gas, and other Gas 1 fuels. See preamble for rationale for selecting a work practice for these units.

Commenter Name: Michael Palazzolo
Commenter Affiliation: Alcoa Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2967.1
Comment Excerpt Number: 7

Comment: Alcoa believes that the 10 percent limitation for oil usage in boilers and heaters designed to burn gas and oil is too restrictive. These units primarily burn gas. However, operators need the flexibility to burn oil for time periods when gas is not unavailable or too costly. Restricting the ability to burn oil in these units without controls will drive owners/operators away from the use of cleaner fuels. We recommend that EPA revise the definition for Unit designed to burn gas to allow 80 percent of annual heat input from gas rather than 10 percent.

Response: See response to comments EPA-HQ-OAR-2002-0058-2840.1, excerpt 12 and EPA-HQ-OAR-2002-0058-2875.1, excerpt 9 for use of back up fuels within Gas 1 units and appropriateness of 10% fuel use limit.

Commenter Name: Donald R. Schregardus
Commenter Affiliation: Department of Defense
Document Control Number: EPA-HQ-OAR-2002-0058-2763.1
Comment Excerpt Number: 2

Comment: The final rule should clarify that the definition of Natural Gas as Liquid Petroleum Gas (§63.7575) includes all acceptable classes of propane.

Propane that meets the specification of ASTM D1835-03a is typically vehicle fuel grade or special-duty propane. There are other specification types of propane that should be acceptable under this regulation (e.g., the Gas Processors Association (GPA) Standard 2140-92.)

Revise the definition of natural gas in §63.7575 as follows:
Natural gas means:

(1) A naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane; or

(2) Liquid petroleum gas, as defined by the American Society for Testing and Materials in ASTM D1835-03a, -Standard Specification, for Liquid Petroleum Gases" (incorporated by reference, see §63.14(b)) or equivalent specification.

Response: See response to comment EPA-HQ-OAR-2002-0058-2849.1, excerpt 12 for Gas 1 subcategory and propane fired boilers.

Commenter Name: Walter Tyler
Commenter Affiliation: Invista
Document Control Number: EPA-HQ-OAR-2002-0058-2761.1
Comment Excerpt Number: 15

Comment: The Gas 1 definition excludes several fuels (e.g., biogas, process offgases without metals) that would have combustion product profiles very similar to natural gas. Biogas generated as offgas from an aerobic wastewater treatment system range between 30% and 60% methane with the bulk of the remainder being carbon dioxide. The composition of these offgases contains minimal impurities and no metals. The burning characteristics would be very comparable to natural gas or refinery gas.

Based on the same rationale applicable to natural gas, INVISTA recommends that the definition of Gas 1 units be modified to allow for the combustion of biogas from wastewater treatment facilities.

Recommended Text at 63.75491(h): Unit designed to burn gas 1 (NG/RG) subcategory includes any boiler or process heater that burns at least 90 percent natural gas and/or refinery gas and/or process off-gases with metals and sulfur content equal to or less than those in natural gas....

Response: EPA has revised the definition of natural gas, consistent with the boiler NSPS definition. Any unit burning any other gaseous fuels other than natural gas or refinery gas must demonstrate that the gases meet the specifications for mercury and H2S content.

Commenter Name: William R. Ermatinger
Commenter Affiliation: Northrop Grumman
Document Control Number: EPA-HQ-OAR-2002-0058-2506.1
Comment Excerpt Number: 24

Comment: If natural gas is chosen as a primary boiler fuel to avoid the excessively high cost or inability to meet the Boiler MACT emission limitations for liquid fuel-fired units, propane is the only backup fuel that is not subject to additional emissions controls. Local storage of propane is more expensive than for other backup fuels. Supplies of propane for delivery are often unreliable, particularly in times of greatest demand and in the quantities that would be required daily at the NGSB shipyard. Although other fuels may be technically viable, such as light distillate or biodiesel blends, if they were to constitute 10 percent or more of a boiler's annual consumption, the boilers would become subject to the full emissions limitations for liquid fuel-fired units. As explained above, the resulting baghouses, electrostatic precipitators, scrubbers, and other add-on controls make those options either financially burdensome or nonviable, which leads to the potential for significant manufacturing downtime during periods of gaseous fuel shortages.

Response: See response to comments EPA-HQ-OAR-2002-0058-2840.1, excerpt 12 and EPA-HQ-OAR-2002-0058-2875.1, excerpt 9 for use of back up fuels within Gas 1 units and appropriateness of 10% fuel use limit.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)

Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 41

Comment: The EPA database is not representative of gas- or liquid-fired boiler and process heater subcategories and is inadequate to determine if further or different subcategorization is needed to meet the need for the rule to be rational and achievable. The database does not include a reasonable collection of different designs and fuels. Nothing indicates that even the most basic range of unit types are represented in the data. For instance, firebox temperature is a critical parameter for process heaters in establishing their combustion characteristics and, thus, their emissions, but nothing in the database indicates a representative range of firebox temperatures, which can differ by as much as 600 degree F among process heaters, is included. Since firebox temperature is a critical part of a process heater‘s design duty, it cannot be changed for emissions control purposes since that would make it unable to serve its process duty. Similarly, it is not even clear how many and what size burners are installed for each unit, whether the unit has NOx controls, or whether the unit is natural draft or forced draft.

Response: EPA is not finalizing emisison limits for gas 1 units and therefore disagrees with further subcategorizing the gas 1 subcategory. See the preamble for how EPA has modified CO limits in the final rule.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 45

Comment: The database also may be biased because it is not clear that it reflects the appropriate ration of boilers to process heaters. For refinery and petrochemical operations, which represent a significant proportion of Gas 1 and Gas 2 boilers and process heaters, there are many more process heaters in the source category than boilers. However, the database contains only somewhat more process heaters than boilers. This is significant because boilers typically are designed differently than process heaters, operate differently, have historically been regulated differently and typically have higher heat duties, more heat integration and generally are located in less congested areas than are process heaters. Additionally, boilers all operate in a fairly narrow range of firebox temperatures, while process heaters are designed for a very wide range of firebox temperatures, depending on the process need, resulting in a much broader range of emissions from process heaters than from boilers. As a result, the database may be biased towards boilers and, thus, may not accurately represent the source category.

Response: See response to comments EPA-HQ-OAR-2002-0058-2761.1, excerpt 15 and EPA-HQ-OAR-2002-0058-2702.1, excerpt 73 for the definition of natural gas needs to be broader to account for non-geological origins of natural gas.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 52

Comment: It is also important to realize that many of the Gas 2 streams are the same gases that make-up the Gas 1 subcategory. For instance, refinery gas often includes PSA gas (hydrogen), petrochemical gas, remediation gas, terminal gas, and/or marine gases if those operations are located in or near a refinery. In many cases, refineries and contiguous chemical, terminal and other operations have joint fuel gas systems. Requiring such operations to segregate the existing systems in order to avoid Gas 2 emission limitations for the refinery equipment will result in non-optimum fuel use and reduced energy efficiency. It will also lead to increased SO2 emissions because some Gas 2 gases that are currently being treated to remove H2S in order to meet refinery H2S limits will not be treated when they are no longer mixed with refinery fuel gas. Similarly, some Gas 2 streams that are now mixed with Gas 1 streams will be destroyed without beneficial heat recovery, in order to avoid the proposed Gas 2 emission limits for boilers and process heaters that fire more than 10% Gas 2, but are not primarily in Gas 2 service.

As discussed in Attachment B, it is clear that Gas 2 streams from most operations and refinery gas have similar compositions and combustion properties (e.g., heating values, Wobbe indices and adiabatic flame temperatures). That is, they are primarily composed of light hydrocarbons, such as methane and ethane, and hydrogen. This must be the case in order for the gas to have adequate heat content and to avoid liquid condensation and because higher molecular weight species are commercially valuable and thus would typically be recovered if they were present in large quantities. For all of these reasons, it is illogical to treat those gases differently (i.e., have them in a different subcategory) just because they occur in a different physical location.

Gas 2 fuels include process gas from chemical plants, landfill gas, digester gas, blast furnace gas, coke oven gas, and PSA gas. However, in the emissions information presented for the Gas 2 sources, most of the 74 sources listed, including all 9 in the floor calculation, appear to be located at chemical plants. Chemical plant process gas and PSA gas are typically very similar in composition to refinery gas and often are components of refinery gas. Thus, the data EPA has on the Gas 2 category is primarily from sources that would be considered Gas 1, except for the location at which they are generated.

Logic would seem to indicate that, at a minimum, chemical plant process gas and PSA gas should be grouped with refinery gas in the Gas 1 category. One solution for the remaining fuels in the Gas 2 category would be to establish a new floor. A better solution would be to combine all gaseous fuels into a single category with a work practice compliance requirement.

Response: We appreciate the input from the commenter. We are not finalizing limits for units firing natural gas, refinery gas, and other Gas 1 fuels. See preamble for rationale for selecting a work practice for these units.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-2702.1
Comment Excerpt Number: 71

Comment: B. EPA should allow other gases to be considered Gas 1.
Other gases that fall within the Gas 2 subcategory should be able to fall under the Gas 1 subcategory if certain criteria are met. For example, thresholds could be set related to minimum HHV, whether combustion of a gaseous stream is self-sustaining, percent composition, or maximum contaminant levels. If a gas other than natural gas/refinery gas meets the criteria, then it should be subject to the same work practice standards and included in the Gas 1 subcategory. There is very little difference between the emissions from top performers in the Gas 2 subcategory as compared to the Gas 1 subcategory; therefore, EPA should simply create one gas-fired subcategory.

Chemical process off-gas is an example that should be treated as Gas 1 with a work practice standard. CIBO believes that process off-gases derived from natural gas or petrochemical feedstocks that have low heating values due to their hydrogen content also provide useful combustion energy and should be treated similarly to Gas 1 units. These process gases provide stable combustion characteristics and typically have low contaminant content due to the nature of the processes. The EPA hydrogen fueled flare document- Basis and Purpose Document on Specifications For Hydrogen-Fueled Flares, Emission Standards Division, U.S. Environmental Protection Agency Office of Air Radiation, Office of Air Quality Planning Standards, March 1998, documents the basis for establishing minimum hydrogen content for unsupported flare combustion. The testing documented established the minimum hydrogen content of 8% by volume as that proven adequate for sustained combustion without support fuel (nonassisted flare operation).

As noted in the document, hydrogen has a lower heat content than organics commonly combusted in flares meeting the prior existing flare specifications and cannot, therefore, be used to satisfy prior control requirements. However, since the combustion of hydrogen is different than the combustion of organics, and the test report demonstrates a destruction efficiency greater than 98 percent, the EPA believes that hydrogen-fueled flares meeting the recommended specifications will achieve a control efficiency of 98 percent or greater. This level of control is equivalent to the level of control achieved by flares meeting the prior existing specifications. In addition to achieving the same destruction efficiency of VOC or organic HAP, these recommended specifications have the added advantage of reducing the formation of secondary pollutants; since the combustion of supplemental fuel would not be required by hydrogen-fueled flares to meet the existing flare specifications.

In another example, EPA does not have enough data on combustion of anaerobic digester gas to differentiate it from natural gas. As such, classification of anaerobic digester gas as Gas 2 is unreasonable. The use of digester gas is being promoted as a way of preventing emissions of potent methane GHGs from wastewater treatment plants, to minimize sludge production and as a way to conserve natural gas usage. The use of digester gas would not be expected to cause an increase in any HAPs. Any potential increase in SO2 emissions is readily controlled by conventional means. If digester gas combustion causes a unit to be regulated under Gas 2, the gas will likely not be burned in boilers or process heaters and will instead be flared resulting in an increase in fuel usage and emissions.

Therefore, CIBO recommends a similar approach be used to establish 8% by volume as a minimum hydrogen content in hydrogen fueled process gases as a criterion that allows its use as a fuel in boilers and process heaters under the Boiler MACT rule and allow consideration as Gas 1 with a work practice MACT approach.

Response: We appreciate the input from the commenter. We are not finalizing limits for units firing natural gas, refinery gas, and other Gas 1 fuels. See preamble for rationale for selecting a work practice for these units.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-2702.1
Comment Excerpt Number: 73

Comment: D. Inconsistencies Relative to use of Landfill Gas.
The Proposed Rule includes the definition of units designed to burn gas 2 as follows:

Unit designed to burn gas 2 (other) subcategory includes any boiler or process heater that burns gaseous fuels other than natural gas and/or refinery gas not combined with any solid or liquid fuels.

Therefore, per this definition, a boiler or process heater firing any percentage of heat input of landfill gas (LFG) would be considered as a gas 2 unit and subject to all Proposed Rule requirements for gas 2, including the emission limits. These onerous requirements are basically at odds with the intentions of the EPA Landfill Methane Outreach Program (LMOP). As stated on the EPA web site:

The U.S. Environmental Protection Agency’s Landfill Methane Outreach Program (LMOP) is a voluntary assistance program that helps to reduce methane emissions from landfills by encouraging the recovery and beneficial use of landfill gas (LFG) as an energy resource. LFG contains methane, a potent greenhouse gas that can be captured and used to fuel power plants, manufacturing facilities, vehicles, homes, and more. (Reference: http://www.epa.gov/lmop/)

Many facilities with affected sources under this rule have implemented projects to burn LFG in boilers and process heaters, some in concert with the EPA LMOP program. While the actual analysis of LFG may vary over time and between landfills, the general composition is well known by EPA to contain methane, CO_2, nitrogen, hydrogen, argon/oxygen, and other trace constituents with a HHV of around 500 Btu/scf. HAP emissions from LFG combustion are not known to be a problem, and in fact, the top performing gas 2 unit for mercury one of the top performing units for D/F was the BMW watertube boiler firing LFG. There is no assurance that other units combusting LFG can achieve those limits due to landfill and combustion unit variability. In addition, the gas 2 emission limits also include an unrealistically low CO limit of 1ppmvd @ 3%O2 that likely cannot be achieved by any boiler or process heater firing any percentage of LFG. For example, one CIBO member package boiler demonstrated CO emissions when firing 27% LFG with natural gas that were more than 2.5x that seen when firing natural gas alone (55 ppm vs 21 ppm both at 3%O2), with a 20% reduction in NOx emissions with the LFG. It is likely that other units would see similar impacts on CO with combustion of LFG. Imposition of the proposed emission limits on units firing LFG will very likely result in a cessation of beneficial burning of LFG in boilers and process heaters for two reasons: first, and most importantly, there is no assurance that all emission limits can be achieved even with application of emissions control technology; and second, installation of emissions controls in an attempt to meet the proposed limits will be prohibitively expensive compared to simply stopping combustion of LFG and instead increase use of natural gas. Thus this Proposed Rule will stop the LMOP program in its tracks relative to use of LFG as boiler and process heater fuel; result in increased criteria pollutant emissions; and result in increased GHG emissions due to flaring of the LFG and alternative use of increased natural gas. CIBO instead recommends that EPA recognize the environmental benefits of using LFG and treat LFG as gas 1 with use of a work practice approach.

Response: EPA has revised the definition of natural gas, which includes some treated landfill gases with a methane content of at least 70 percent. For other landfill gas fuels, if the LFG is demonstrated to fall below the gas specifications, as discussed in the final rule, the boiler can qualify for a work practice standard.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 246

Comment: HAP Formation and Emissions from Gas Combustion
Gaseous fuels used in industrial processes typically contain a range of different hydrocarbons and/or hydrogen. Pipeline natural gas consists primarily of methane, with smaller amounts of ethane and other saturated hydrocarbons up to C5 or C6 (Table 1). Refinery fuel gases also consist primarily of methane, with smaller amounts of both saturated and unsaturated hydrocarbons, but also may contain significant amounts of hydrogen (Figure 1). Petrochemical process gas fuels typically have a similar range of compositions.
HAP emissions from gas-fired combustion generally arise from:
Fuel contaminants such as particles, mercury and chlorine compounds;
Combustion conditions that produce particles and organic compounds;
Contaminants in the combustion air such as particles, mercury and chlorine compounds.
Contaminants in other streams that may be introduced to the boiler or process heater gas

path such as vent gas streams, NOX control reagents (e.g. ammonia, urea), or water. Elements in the fuel such as mercury and chlorine are potential sources of mercury and hydrogen chloride (HCl) in the combustion products, to the degree they pass through the system. Mercury is highly mobile due to its volatility. The presence of mercury in unprocessed natural gas varies considerably among regional sources. Mercury produces undesirable effects in natural gas processing equipment, and is typically removed in carbon beds before processing or with condensates before distribution to sales pipelines. Thus, the concentration of mercury in processed natural gas delivered to the pipeline is typically much lower than the raw produced gas.

A survey of processed natural gas from 19 different fields in the US showed that mercury was undetected in 15 samples at detection limits of 0.012 lb/trillion Btu and in 3 samples at detection limits of 0.0012 lb/trillion Btu (GRI, 1994). Mercury was detected in only a single sample at 0.0012 lb/trillion Btu, just above the detection limit. Halocarbons (including chlorinated compounds) were undetectable in all samples at a detection limit of 0.1 ppmv.

GRI and EPRI tested two gas-fired utility boilers and found mercury undetectable in the stack at detection limits of 0.34 and 0.35 lb/trillion Btu (GRI, 1995). They did not measure HCl or dioxins/furans (D/F). Carbon monoxide (CO) ranged from 0.06 to 0.3 lb/MMBtu over a range of loads and operating conditions. CO detection limits were reported as 0.0037 and 0.00073 lb/MMBtu. PM was not measured. Total hydrocarbons (THC), as methane, ranged from 5 to 20 lb/trillion Btu. Mercury was detected in one fuel gas sample at 0.0013 lb/trillion Btu. Mercury was not detected in two natural gas samples in gas turbine tests at detection limits of 0.0006 lb/trillion Btu.

Contaminants in the combustion air also are a potential source of stack emissions. The upper end of the range of HCl and dioxins/furans toxic equivalent (TEQ) concentrations measured in ambient air are comparable to the proposed emission limits proposed for Gas 2 fuels (Table 2). Concentrations of mercury and particulate matter are considerably below the proposed emission limits for either gas fuel subcategories, while CO concentrations are similar. This suggests that the combustion air in gas-fired combustion systems potentially contributes to measured CO, hydrogen chloride (HCl) and dioxins/furans TEQ emissions, and that stack emissions may be difficult to differentiate from ambient background levels at the proposed emission limit concentrations.

Volatile and semi-volatile organic HAPs (O-HAPs) are thought to be formed in flames via various chemical pathways that form volatile, aromatic and polycyclic compounds (e.g., Marinov et al., 1996 and others). Under normal combustion conditions, these compounds are also destroyed but trace amounts may escape complete combustion. Pilot-scale combustion tests under well-controlled conditions shows that gaseous hydrocarbons tend to burn very cleanly regardless of the distribution of individual lighter (C1-C6) hydrocarbons within a blend, over a fairly wide range of operating conditions and temperatures (Seebold, 1997; England et al., 2001). Gas fuel blends spiked with olefinic and aliphatic components also produced similar (very low) levels of O-HAP emissions under normal combustion conditions (ibid.). Comparison of pilot-scale and earlier field data for different gas fuel compositions also shows that O-HAP emissions are similar among fuels ranging in heating value from approximately 600 to 1800 Btu/scf (ibid.).

The absence of a measurable difference in O-HAP emissions for such a wide range of fuel compositions strongly suggests that if combustion conditions are maintained within normal bounds that O-HAP emissions are not significantly affected by fuel composition.

Response: EPA recognizes that mercury content of natural gas can vary. Some natural gas is drilled locally with slight differences depending on the geographic location while other natural gas is imported and stored as LNG. Based on data available from Calgon corporation we have identified the range of mercury content of natural gas in North Amercia and established a maximum mercury specification for any gas fuel that can qualify as a gas 1 fuel using the maximum mercury content of the reported mercury ranges.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 260

Comment: The Gas 1 CO data also offer little insight into which controls are associated with lower CO emissions (Figure 2). The CO floor is populated largely by units with no controls, except for a few units primarily with low-NOX burners or selective catalytic reduction (SCR) systems for NOX emission control. There are four units with oxidation catalysts, none of which are in the floor. CO for these units ranges from slightly below 1 ppm to nearly 10 ppm. There are data in the ICR database for two additional units with oxidation catalysts that EPA did not use due to emission unit conversion problems. An approximate conversion was made for this discussion (Figure 3), showing even higher CO emissions for these two units assuming the approximate conversion is valid. There are a number of units with FGR for NOX control. These units populate the higher end of the CO range with most units between approximately 10 and 100 ppm. This is expected as discussed above. There are many units with low-NOX burners, some also with FGR. Reported CO emissions from these units range from 0.1 to a few hundred ppm, with most units populating the upper middle range of the population, which also is expected. Low-NOX gas burners achieve NOX reduction via staged combustion to achieve lower temperatures and delayed mixing and/or (fuel-lean) premixing of the fuel and air. This creates conditions that are more challenging for CO burnout, and elevated CO is often a result. There are a few units with water or steam injection for NOX control, which have among the highest CO emissions from approximately 20 to a few hundred ppm. Depending on design, water or steam injection can be an effective, low capital cost NOX control solution but elevated CO emissions are a common consequence of the rapid quench that occurs in the vicinity of the injectors. SCR may potentially have some impact on CO via catalytic oxidation, although this is speculative. Three near-identical units firing the same fuel at one facility have SCR and a wet electrostatic precipitator (ESP) and are jet fuel capable but fired refinery gas during the reported tests. One unit is in the floor, one unit has CO approximately 1 order of magnitude higher and the third unit has CO approximately 3 orders of magnitude higher. There are several units with SCR alone. Most of the units have CO emissions between 1 and 30 ppm, with three units below 1 ppm. There is no beneficial effect of SCR on CO evident in the data.

Response: EPA did not rank and analyze emissions in each subcategory according to the control devices installed but instead ranked the units based on the emissions measured. EPA is not finalizing CO emission limits for gas 1 units.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 263

Comment: The Gas 1 data set is much larger, encompassing data for hundreds of units. Nearly all the data are survey data from Phase I of the ICR. Most units are reported to have no emission controls. The data encompass a number of units with a variety of emission controls, primarily technologies for NOx emissions control and four units with oxidation catalyst for CO control. A few units are reported to have cyclones, ESPs and other particulate matter control devices although it‘s not clear why they would have needed these when firing natural gas or refinery gas these should be further investigated to determine if they are appropriately characterized. Examining the filterable PM emissions data for different technologies shows there is no clear trend suggesting an effective emission control technology for Gas 1 units (Figure 5). The data for each technology span a wide range of PM emissions and no technologies dominate the lower range of reported emission data. Thus, there is little insight offered by the ICR data with respect to effective filterable PM control technologies for gas-fired units.

Response: See response to comment EPA-HQ-OAR-2002-0058-2960.1, excerpt 260 for HAP emission control devices installed on Gas 1 units.

Commenter Name: Cynthia L. Karlic
Commenter Affiliation: NRG Energy, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2822.1
Comment Excerpt Number: 2

Comment: The proposed regulations do state that "Gaseous fuel boilers and process heaters that burn liquid fuel during periods of gas curtailment, gas supply emergencies or for periodic testing of liquid fuel not to exceed a combined total of 48 hours during any calendar year are not included..." in the Oil ICI Boiler category. The 48 hour limit is too restrictive for the dual fuel-fired boilers in that the 48 hours equates to only approximately 0.5% of operating hours on an annual basis and only if the one of the stated conditions existed. For consistency purposes, the ICI MACT rule should use the same definition for oil and gas fired boilers as is used in Part 75 of the Acid Rain regulations. This would allow a three-year average of at least 90 percent heat input from gas-firing with no individual year less than 85%.

Response: See response to comment EPA-HQ-OAR-2002-0058-2792.1, excerpt 223 for the 48 hour a year provision.
See response to comments EPA-HQ-OAR-2002-0058-2840.1, excerpt 12 and EPA-HQ-OAR-2002-0058-2875.1, excerpt 9 for use of back up fuels within Gas 1 units and appropriateness of 10% fuel use limit.

Commenter Name: Edward Bortz
Commenter Affiliation: SP Newsprint Co LLC
Document Control Number: EPA-HQ-OAR-2002-0058-3128
Comment Excerpt Number: 2

Comment: We support the concept in the proposed rule that a natural gas fired boiler that burns 10 percent or less oil or biomass should not be considered an oil or biomass fired boiler. However, consistent with the NSPS program, we believe that the appropriate threshold should be set at 30 percent.

Response: See response to comments EPA-HQ-OAR-2002-0058-2840.1, excerpt 12 and EPA-HQ-OAR-2002-0058-2875.1, excerpt 9 for use of back up fuels within Gas 1 units and appropriateness of 10% fuel use limit.

Commenter Name: Russ A. Wozniak
Commenter Affiliation: Dow Chemical Company
Document Control Number: EPA-HQ-OAR-2002-0058-2632.1
Comment Excerpt Number: 7

Comment: EPA Should Include Petrochemical and Chemical Plant Off-Gas Streams in the Gas 1 Subcategory because The Use of Petrochemical and Chemical Plant Off-Gas Streams as Fuel is Essential to Promote Energy Efficiency and the Composition of these Gas Streams is Similar to Natural Gas and Refinery Gas. Large integrated chemical plant sites strive to be as energy efficient as possible. One way to promote energy efficiency is to capture off-gas from petrochemical and chemical plant off-gas streams and re-use these streams as fuel in a variety of combustion sources. Typically these off-gas streams are blended with natural gas and then used in combustion sources at the plant sites. One of the largest off-gas streams is the fuel produced from on-site ethylene production plants. The ethylene process off-gas is very similar in composition to natural gas and refinery gas. This off-gas stream is a very clean fuel and a typical composition is shown in the table below. The main difference is that this stream contains a significant amount of hydrogen which is a very clean fuel to use.

Column A represents a natural gas stream and Column B represents a typical ethylene process off-gas stream from an ethylene production plant. [See submittal for un-numbered, un-named table.]

Response: We appreciate the input from the commenter. We are not finalizing limits for units firing natural gas, refinery gas, and other Gas 1 fuels. See preamble for rationale for selecting a work practice for these units.

Commenter Name: John C. deRuyter
Commenter Affiliation: DuPont
Document Control Number: EPA-HQ-OAR-2002-0058-2793.1
Comment Excerpt Number: 7

Comment: Landfill Gas

Another case of gases currently considered as Gas 2 that should be treated similarly to Gas 1 with a work practice is landfill gas combustion in boilers and process heaters. The proposed rule highlights inconsistencies within EPA relative to use of Landfill Gas (LFG).

A boiler or process heater firing any percentage of heat input of LFG would be considered as a Gas 2 unit and subject to all proposed rule requirements for Gas 2, including the emission limits. These onerous requirements are basically at odds with the intentions of the EPA Landfill Methane Outreach Program (LMOP). As stated on the EPA web site: The U.S. Environmental Protection Agency's Landfill Methane Outreach Program (LMOP) is a voluntary assistance program that helps to reduce methane emissions from landfills by encouraging the recovery and beneficial use of landfill gas (LFG) as an energy resource. LFG contains methane, a potent greenhouse gas that can be captured and used to fuel power plants, manufacturing facilities, vehicles, homes, and more. (Reference: http://www.epa.gov/lmop/)

Many facilities with affected sources under this rule have implemented projects to burn LFG in boilers and process heaters, some in concert with the EPA LMOP program. While the actual analysis of LFG may vary over time and between landfills, the general composition is well known by EPA to contain methane, CO_2, nitrogen, hydrogen, argon/oxygen, and other trace constituents with a HHV of around 500 Btu/scf. HAP emissions from LFG combustion are not known to be a problem, and in fact, the top performing Gas 2 unit for mercury and one of the top performing units for D/F was the BMW watertube boiler firing LFG. There is no assurance that other units combusting LFG can achieve those limits due to landfill materials/LFG and combustion unit variability.

Response: See response to comments EPA-HQ-OAR-2002-0058-2761.1, excerpt 15 and EPA-HQ-OAR-2002-0058-2702.1, excerpt 73 for the definition of natural gas needs to be broader to account for non-geological origins of natural gas.

Commenter Name: Russ A. Wozniak
Commenter Affiliation: Dow Chemical Company
Document Control Number: EPA-HQ-OAR-2002-0058-2632.1

Comment Excerpt Number: 9

Comment: EPA should include petrochemical and chemical plant process off-gas streams with refinery gases since they are similar in composition to natural gas. Dow suggests the following edits to the definitions in Section 63.7575:

Unit Designed to Burn Gas 1 (NG/RG) subcategory includes any boiler or process heater that burns at least 90 percent natural gas and/or refinery gas or off-gas streams from petrochemical and chemical plant processes on a heat input basis on an annual average.

Response: We appreciate the input from the commenter. We are not finalizing limits for units firing natural gas, refinery gas, and other Gas 1 fuels. See preamble for rationale for selecting a work practice for these units.

Commenter Name: Wayne Smith
Commenter Affiliation: Westlake Chemical Corporation
Document Control Number: EPA-HQ-OAR-2002-0058-2785.1
Comment Excerpt Number: 9

Comment: Refinery Gas vs. Petrochemical Off-Gas Streams: The Proposed Rules provide special provisions for Refinery Gas combustion sources, which does not appear to include Petrochemical Off-Gas Streams. We think the Petrochemical Off-Gas Streams (with non-halogenated hydrocarbons) should be afforded the same regulatory accommodations as refinery gas. An excellent example of Petrochemical Off-Gas Streams that should be afforded this accommodation is ethylene plant process fuel gas, which is primarily hydrogen and methane, and is an ideal fuel source.

Response: We appreciate the input from the commenter. We are not finalizing limits for units firing natural gas, refinery gas, and other Gas 1 fuels. See preamble for rationale for selecting a work practice for these units.

Commenter Name: John Hopewell
Commenter Affiliation: American Coatings Association
Document Control Number: EPA-HQ-OAR-2002-0058-2886.1
Comment Excerpt Number: 25

Comment: EPA should recognize boilers are not always designed to burn one fuel. ACA agrees that gas fired boilers burning liquid during periods of gas curtailment are gas fired boilers, but should be allowed to burn other fuels up to 10 percent of the time.

Response: See response to comments EPA-HQ-OAR-2002-0058-2840.1, excerpt 12 and EPA-HQ-OAR-2002-0058-2875.1, excerpt 9 for use of back up fuels within Gas 1 units and appropriateness of 10% fuel use limit.

Commenter Name: Russ A. Wozniak
Commenter Affiliation: Dow Chemical Company
Document Control Number: EPA-HQ-OAR-2002-0058-2632.1
Comment Excerpt Number: 85

Comment: EPA Should Modify the Definition of "Unit Designed to Burn Gas 1 (NG/RG) Subcategory." Section 63.7575 of EPA's proposed rule defines "Unit designed to burn gas 1 (NG/RG) subcategory" as "includes any boiler or process heater that burns at least 90 percent natural gas and/or refinery gas on a heat input basis on an annual average." In the memorandum "Development of Baseline Emission Factors for Boilers and Process Heaters at Commercial, Industrial, and Institutional Facilities" dated April 2010 from Amanda Singleton and Graham Gibson, ERG to Jim Eddinger, U. S. EPA, OAQPS, the process is described for developing baseline emission factors. That process includes a step to categorize fuels combusted and control devices utilized. Then emissions data for each combustion unit was averaged and a unit-specific baseline emission factor assigned.

Fuels listed in the 2008 Questionnaire for Boilers, Process Heaters, Incinerators and Other Combustion Units (ICR No. 2286.01, OMB Control No. 2060-0616, EPA Form No. 5900-122) were categorized into one of 11 fuel categories listed in Table 2 which ultimately ended up in the 11 subcategories defined in the proposed rule. Specific fuel types were mapped to the categories using Table B.1 of Appendix B.

From Table B.1 the fuel category "Natural Gas & Other Non-Process Gases" lists Hydrogen, LPG, Natural Gas, Pilot Gas, Propane, and Refinery Gas. This category appears to be the source category used in MACT floor analyses resulting in the subcategory defined above. From the fuel type mapping it is seen that this category contains non-process fuels besides natural gas and refinery gas. The subcategory "Unit designed to burn gas 1 (NG/RG)" includes hydrogen, LPG, and propane." In addition to the EPA MACT floor analysis conducted by EPA that included these fuels in that subcategory, it is evident that such fuels would not include the five grouped HAPs for boilers or process heaters: mercury, non-mercury metallic HAP, inorganic HAP, non-dioxin organic HAP, and D/F.

Modifying the definition as proposed below enhances user understanding of the subcategory while remaining consistent with the MACT floor analysis. Thus, Dow proposes the following revised definitions for inclusion into the final rule:

Unit Designed to Burn Gas 1 (NG/RG) subcategory includes any boiler or process heater that burns at least 90 percent natural gas and/or refinery gas or off-gas streams from petrochemical and chemical plant processes on a heat input basis on an annual average.

In conjunction with the definition of "Unit Designed to Burn Gas 1 (NG/RG), Dow suggests the following definition to add to the regulatory text in Section 63.7575:

Refinery Gas and Off-Gas Streams from Petrochemical and Chemical Plant processes - means "a gaseous mixture of methane, light hydrocarbons, hydrogen, and other miscellaneous species (nitrogen, carbon dioxide, hydrogen sulfide, etc.) in the refining of crude oil or in the production of chemicals or petrochemicals and that is separated for use as a fuel in boilers and process heaters throughout the site.

Response: We appreciate the input from the commenter. We are not finalizing limits for units firing natural gas, refinery gas, and other Gas 1 fuels. See preamble for rationale for selecting a work practice for these units.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 59

Comment: ACC also conducted a review of the data used to develop the Gas 2 category CO limits. Gas 2 fuels may include: process gas from a chemical plant, landfill gas, digester gas, blast furnace gas, coke oven gas, or PSA gas. However, most of the 74 Gas 2 sources, , including all 9 in the floor calculation, appear to be located at chemical plants. Chemical plant "process gas" is typically similar in composition to refinery gas, whereas the other Gas 2 fuel types (landfill, coke oven, etc.) generally have much greater variability in their composition. This variability makes it more difficult to control the combustion airflow, and therefore, CO emissions. As such, chemical plant process gas is not representative of the "other gaseous fuel" units, yet it has been used exclusively to set the CO floor for Gas 2.

We believe that chemical plant process gas should be grouped with refinery gas in the Gas1 category. In so doing, EPA should establish a new floor for the remaining fuels in the Gas 2 category so that the standards are representative of and based on the composition of those gases (note that the average CO emissions of the 74 units in the Gas 2 data set, including all the chemical plant process gas units, is over 150 ppm CO). A better solution would be to combine all gaseous fuels into a single category, with a work practice compliance requirement.

Response: We appreciate the input from the commenter. We are not finalizing limits for units firing natural gas, refinery gas, and other Gas 1 fuels. See preamble for rationale for selecting a work practice for these units.

Commenter Name: Bethany J. Johnson
Commenter Affiliation: The Boeing Company
Document Control Number: EPA-HQ-OAR-2002-0058-2894.1

Comment Excerpt Number: 7

Comment: Clarify the Definition of "Unit Designed to Burn Oil" Subcategory to Avoid Overlap with the "Unit Designed to Burn Gas 1 (NG/RG)" Subcategory. A boiler or process heater that meets the currently proposed definition of a "unit designed to burn gas 1 (NG/RG) subcategory" could also meet the proposed definition for a "unit designed to burn oil subcategory" if, for example, it burns liquid fuel for periodic testing exceeding a combined total of 48 hours during any calendar year, but not exceeding 10 percent (heat input basis) on an annual average. We request that the oil subcategory definition in proposed section 63.7575 be changed as follows: "Unit designed to burn oil subcategory includes any boiler or process heater that burns any liquid fuel, but less than 10 percent solid fuel on a heat input basis on an annual average, either alone or in combination with gaseous fuels. Gaseous fuel boilers and process heaters that meet the definition for the "unit designed to burn gas 1 (NG/RG) subcategory" burn liquid fuel during periods of gac curtailment, gas supply emergencies or for periodic testing ,9-f liquid fuel not to exceed a are not included in this definition."

Response: See response to comment EPA-HQ-OAR-2002-0058-2792.1, excerpt 223 for the 48 hour a year provision.

Commenter Name: Sarah E. Amick
Commenter Affiliation: Rubber Manufacturers Association
Document Control Number: EPA-HQ-OAR-2002-0058-2941.1
Comment Excerpt Number: 1

Comment: Rubber Manufacturers Association (RMA) tire manufacturer member companies own and operate 56 major source boilers, at 17 facilities in 13 states[8 Major source boilers at RMA member tire manufacturing facilities are located in the following states: Alabama, Arkansas, Illinois, Indiana, Kansas, Kentucky, Mississippi, North Carolina, Ohio, Oklahoma, South Carolina, Tennessee and Virginia] that would be impacted by the proposed rule. These boilers range in size from 19 MMBtu/ hr to 190 MMBtu/hr and combust either natural gas or a combination of natural gas and light liquid fuel oils. Under the proposed Boiler MACT rule, boilers burning greater than 10% liquid fuel are classified as liquid fuel boilers. We believe the fuel category thresholds are too low and should not be based on the design fuel. RMA recommends that EPA classify boilers based on predominant use of a particular fuel, where predominant use is defined as over 50% of the fuel use, excluding fuel used during periods of curtailment.

Requiring boilers that periodically burn more than 10% liquid fuel (per year) to preserve the ability to burn liquid fuel by installing costly add-on controls that may rarely be used seems counter productive. Again, categorizing boilers based on predominant use would alleviate the burned of installing add-on controls for boilers that predominantly combust natural gas.

Response: See response to comments EPA-HQ-OAR-2002-0058-2840.1, excerpt 12 and EPA-HQ-OAR-2002-0058-2875.1, excerpt 9 for use of back up fuels within Gas 1 units and appropriateness of 10% fuel use limit.

Commenter Name: Frederick R. Albrecht
Commenter Affiliation: SCA Tissue
Document Control Number: EPA-HQ-OAR-2002-0058-2843.1
Comment Excerpt Number: 1

Comment: EPA is defining a gas boiler as one that burns at least 90% gas and 10% any other fuel. We are comfortable with this definition. However, this definition further states that if a gas boiler burns another fuel for more than 48 hours in a year due to a natural gas emergency, this boiler then becomes categorized as a liquid gas boiler. This has the potential of being a major problem. SCA has an agreement with our natural gas provider to be curtailed in unique cases. For instance, if temperatures in Wisconsin get very cold, and demand for natural gas spikes, SCA will defer getting our natural gas so that a sufficient supply is available to hospitals, schools and homes. During these times, SCA would switch to oil until the curtailment ends. Under the new rules, if this curtailment — which clearly benefits the common good of the region — were to extend past 48 hours in a year, SCA could be classified by the EPA as a ‘liquid fuel’ burner and be subject to the many rules of this category.
There are other examples of this nature such as when SCA needs to periodically test our oil burners to ensure they are working properly or when we have to use up an aging oil supply before it becomes unusable.
We ask that the EPA keep the 90/10 standard but eliminate the extremely unrealistic 48 hour a year provision.

Response: See response to comment EPA-HQ-OAR-2002-0058-2792.1, excerpt 223 for the 48 hour a year provision.

Commenter Name: Michael Potter
Commenter Affiliation: Goodyear Tire and Rubber Company
Document Control Number: EPA-HQ-OAR-2002-0058-3181
Comment Excerpt Number: 1

Comment: It is not clear to Goodyear whether the period of fuel oil usage reported under section 63.7545(f) is considered to be a deviation, or whether the fuel oil used during the curtailment or supply interruption period is to be included in the calculation of the 10 percent annual heat input specified in the definition of liquid fuel subcategory.

The proposed regulations should exclude backup fuel oil usage during routine periodic equipment checks and maintenance and periods of gas curtailment and supply interruption from the applicability determination for the liquid fuel subcategory.

The proposed Boiler MACT rules anticipate the possibility of gas curtailment and supply interruptions, but have not gone far enough to address such eventualities. The definition in proposed 40 CFR section 63.7575 for the liquid fuel subcategory provides that liquid fuel (i.e. oil) can provide up to 10 percent of the annual heat input to a boiler before the liquid fuel category applies. Boilers with backup oil capability must routinely burn some standby fuel on a periodic basis to assure that the backup fuel equipment is maintained properly and will be in good operating condition should a gas curtailment or supply interruption occur and combustion of backup fuel be needed. This routine periodic usage presumably must be counted toward the 10 percent allowance before the liquid fuel subcategory goes into effect.

In addition, it is impossible for a boiler owner/operator to predict how often or for how long a curtailment or interruption might occur. Even if EPA is properly notified of the use of oil during curtailment or interruption periods in accordance with 40 CFR section 63.7545(f), it is not evident that oil used during a curtailment or interruption period would be excluded from the 10 percent heat input allowed before the liquid fuel subcategory goes into effect.

If the routine periodic use of backup fuel oil for equipment checks and maintenance and use of backup fuel oil during extended periods of curtailment or interruption are counted toward the 10 percent heat input specified in the liquid fuel subcategory, that threshold can easily and unexpectedly be exceeded. To resolve this unreasonable situation, the proposed regulations should be revised to provide that uses of backup fuel oil for purposes of routine periodic equipment checks and maintenance, along with all fuel oil Usage during periods of actual gas curtailments and interruptions, are specifically excluded from counting toward the 10 percent heat input trigger for the liquid fuel category applicability.

Response: See response to comments EPA-HQ-OAR-2002-0058-2840.1, excerpt 12 and EPA-HQ-OAR-2002-0058-2875.1, excerpt 9 for use of back up fuels within Gas 1 units and appropriateness of 10% fuel use limit.

Commenter Name: Robert C. Carroll
Commenter Affiliation: Renovar Energy Corp
Document Control Number: EPA-HQ-OAR-2002-0058-3183
Comment Excerpt Number: 2

Comment: We would urge the EPA to exempt Landfill Gas from this proposed rule by including Landfill Gas within the "unit designed to burn gas I (NG/RG) subcategory" definition as listed in subsection 63.7575. Landfill Gas would then receive the exemptions from the rule given to natural gas and innovative renewable energy companies such as ours would not be put out of business.

Response: See response to comments EPA-HQ-OAR-2002-0058-2761.1, excerpt 15 and EPA-HQ-OAR-2002-0058-2702.1, excerpt 73 for the definition of natural gas needs to be broader to account for non-geological origins of natural gas.

Commenter Name: Paul Bredwell
Commenter Affiliation: U.S. Poultry and Egg Association, National Turkey Federation, and National Chicken Council
Document Control Number: EPA-HQ-OAR-2002-0058-2902.1
Comment Excerpt Number: 2

Comment: EPA should also consider the following for all natural gas-fired boilers and process heaters:
Work practices for natural gas boilers and process heaters are appropriate in lieu of emission limits;
Given the very low-HAP emissions of natural gas-fired units, EPA should consider delisting these sources from regulation under CAA section 112(c)(9);
The proposed energy assessment is not supported by the statute and is not demonstrated as providing any HAP reduction;
EPA's definition of natural gas needs to be broader to account for non-geological origins of natural gas such as landfill gas, biogas, and synthetic gas derived from coal.

Response: See response to comments EPA-HQ-OAR-2002-0058-2761.1, excerpt 15 and EPA-HQ-OAR-2002-0058-2702.1, excerpt 73 for the definition of natural gas needs to be broader to account for non-geological origins of natural gas.

Commenter Name: Sarah E. Amick
Commenter Affiliation: Rubber Manufacturers Association
Document Control Number: EPA-HQ-OAR-2002-0058-2941.1
Comment Excerpt Number: 4

Comment: Units that burn gas and <10% liquid on an annual basis would appear to be in both a "gas subcategory" and the "unit designed to burn oil subcategory." Furthermore, the proposed exclusion for gas-fired units that burn oil during periods of gas curtailment, gas supply emergencies or for periodic testing of liquid fuel from the liquid subcategory would appear to be unworkable as drafted because it appears to only allow oil firing for 48 hours a year. As experience has repeatedly shown, natural gas curtailments would likely almost always exceed 48 hours. We assume the 48 hours was meant to apply only to the testing situation, and the draft language does not accurately represent the Agency intent. To address these two issues, RMA recommends that EPA clarify that gaseous fuel boilers and process heaters that burn liquid fuel during periods of gas curtailment or gas supply emergencies are not included in the definition of "units designed to burn oil subcategory."

Response: See response to comment EPA-HQ-OAR-2002-0058-2792.1, excerpt 223 for the 48 hour a year provision.

Commenter Name: Mick Baranko
Commenter Affiliation: Douglas County Forest Products
Document Control Number: EPA-HQ-OAR-2002-0058-2856.1
Comment Excerpt Number: 4

Comment: We support the concept in the proposed rule that a natural gas fired boiler that burns 10 percent or less oil or biomass should not be considered an oil or biomass fired boiler. However, consistent with the NSPS program, we believe that the appropriate threshold should be set at 30 percent.

Response: See response to comments EPA-HQ-OAR-2002-0058-2840.1, excerpt 12 and EPA-HQ-OAR-2002-0058-2875.1, excerpt 9 for use of back up fuels within Gas 1 units and appropriateness of 10% fuel use limit.

Commenter Name: Catherine W. McCuthen
Commenter Affiliation: Blue Heron Paper Company
Document Control Number: EPA-HQ-OAR-2002-0058-2892.1
Comment Excerpt Number: 4

Comment: We support the concept in the proposed rule that a natural gas fired boiler that burns 10 percent or less oil or biomass should not be considered an oil or biomass fired boiler. However, consistent with the NSPS program, we believe that the appropriate threshold should be set at 30 percent. We also encourage EPA to add materials that EPA's definition of solid waste rule ultimately defines as wastes to the list of materials that that can constitute up to 30 percent of the heat input without the boiler being considered an incinerator.

Response: See response to comments EPA-HQ-OAR-2002-0058-2840.1, excerpt 12 and EPA-HQ-OAR-2002-0058-2875.1, excerpt 9 for use of back up fuels within Gas 1 units and appropriateness of 10% fuel use limit.

Commenter Name: Chris Welch
Commenter Affiliation: Colorado Springs Utilities
Document Control Number: EPA-HQ-OAR-2002-0058-2943.1
Comment Excerpt Number: 5

Comment: This definition is not inclusive enough to capture all of the situations where a unit primarily fired on natural gas might have to utilize its backup fuel oil. For example, many Title V permits require periodic opacity measurements to be performed while a unit is burning its backup fuel. Scheduling this during a period of gas curtailment would be nearly impossible, and a period of gas curtailment may not even occur within a compliance period. In addition, the

infrequency of operation of this equipment requires routine periodic testing while the unit fires backup fuel to ensure functionality.
One way to include these additional situations would be to expand the statement within the body to mimic or simply reference the definition of Gas-fired boiler found in 63.11237. "Gas-fired boiler includes any boiler that bums gaseous fuels not combined with any solid fuels, bums liquid fuel only during periods of gas curtailment, gas supply emergencies, or periodic testing on liquid fuel. Periodic testing of liquid fuel shall not exceed a combined total of 48 hours during any calendar year."

Response: See response to comment EPA-HQ-OAR-2002-0058-2792.1, excerpt 223 for the 48 hour a year provision.

Commenter Name: John Steber
Commenter Affiliation: Performance Fibers
Document Control Number: EPA-HQ-OAR-2002-0058-3174
Comment Excerpt Number: 5

Comment: Additionally, PFI requests guidance and clarification on the following issues related to this definition. Is the intent to include the heat input of alternative fuel use during periods of natural gas curtailment or supply interruption, as defined under section 63.7575, toward the assessment of the annual average under the Gas 1 subcategory —Unfortunately, a facility operating under a curtailment contract with a natural gas supplier has no control over the frequency or duration of such events. Therefore, PFI believes that the alternative fuel use during such time periods should be excluded in the assessment of this subcategory determination.

Response: See response to comments EPA-HQ-OAR-2002-0058-2840.1, excerpt 12 and EPA-HQ-OAR-2002-0058-2875.1, excerpt 9 for use of back up fuels within Gas 1 units and appropriateness of 10% fuel use limit.

EPA has modified the 48-hour periodic testing and gas curtailment provision of the unit designed to burn liquid subcategories. If a unit is burning liquid fuels under either of these conditions these periods to not count towards the heat input threshold. In order to be a gas 1 unit the unit must only burn liquid fuels during these specific exempted periods, burning any other fuel could cause the unit to be part of another subcategory.

Commenter Name: Shelley Schneider
Commenter Affiliation: Nebraska Department of Environmental Quality
Document Control Number: EPA-HQ-OAR-2002-0058-2820.1
Comment Excerpt Number: 5

Comment: EPA includes in the Gas 2 subcategory gaseous fuels other than natural gas and/or refinery gas. The definition of natural gas is defined as "a naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane; or (2) Liquid petroleum gas..." Biogas does not meet the natural gas definition and is therefore included in the Gas 2 subcategory.

Sources within the Gas 2 subcategory are required to comply with numerical emission standards and conduct costly stack testing. The Gas 1 subcategory includes units burning 90% natural gas/refinery gas on an annual heat input basis. Units included in the Gas 1 subcategory are subject to less stringent work practice standards. NDEQ asks EPA to consider including biogas in the natural gas/refinery gas subcategory or at a minimum increasing the percentage of other gases allowed to be burned while still maintaining their Gas 1 status.

Response: See response to comments EPA-HQ-OAR-2002-0058-2761.1, excerpt 15 and EPA-HQ-OAR-2002-0058-2702.1, excerpt 73 for the definition of natural gas needs to be broader to account for non-geological origins of natural gas.

Commenter Name: Daniel Moss
Commenter Affiliation: Society of Chemical Manufacturers and Affiliates
Document Control Number: EPA-HQ-OAR-2002-0058-2926.1
Comment Excerpt Number: 6

Comment: Finally, we urge the Agency to clarify several uncertainties about which units are considered to be gas-fired under the major source rule, and what their notice obligations are. Gas-fired units predominate among our members' boilers, and some SOCMA members have dual-fuel units that can burn gas or oil. The differentiating point between oil and gas-fired units is thus of great importance to SOCMA members. But the proposal is inconsistent on this point.

The preamble declares that "the gas categories" comprise any unit that "burns gaseous fuel and less than 10 percent, on an annual average heat input basis, of liquid or solid fuel." SOCMA supports this characterization, which is consistent with the characterizations of coal, biomass and liquid-fired units that immediately precede it in the preamble.

However, the preambular characterization of gas-fired boilers is contradicted by the proposed regulatory definitions of gas and oil-fired units. One of those definitions also conflicts with the comparable definition in the proposed Area Source Boiler rule: "The definition of "Unit designed to burn gas 1" is consistent with the preamble: any unit "that burns at least 90 percent natural gas and/or refinery gas on a heat input basis on an annual average" is a Gas 1 unit. Thus, a unit that burned 92% natural gas and 8% oil would be a Gas 1 unit."

But the definition of "Unit designed to burn gas 2 (other)" creates a conflict: It includes any unit "that burns gaseous fuels other than natural gas and/or refinery gas not combined with any solid or liquid fuels."5 Thus, a unit that burned 99% process gas and 1% oil would not qualify, and would presumably be a liquid-fired boiler.

Even more confusing, the definition of the “Unit designed to burn oil” subcategory includes units “that burn any liquid fuel.”6 Its only exemption is for “gaseous fuel boilers . . . that burn liquid fuel during periods of gas curtailment, gas supply emergencies or for periodic testing of liquid fuel not to exceed a combined total of 48 hours during any calendar year.” This would imply that a natural gas-fired boiler that burned oil 5% of the time, but not for reasons related to curtailment, emergency or testing, might qualify as a Gas l unit, but would also be considered an oil-fired unit.

Even more confusing, the foregoing 48 hour limitation, as expressed in the definition of “gas-fired boiler” contained in the proposed Area Source Boiler rule, is clearly limited only to periodic testing and does not apply to curtailment or supply emergency periods.

Even more confusing, proposed § 63.7445(f) requires a “natural gas-fired boiler” that intends to use a fuel other than natural gas “or equivalent” (presumably this means refinery gas – so why not just say a “Gas 1 unit”?) to give the permitting agency notice within 48 hours of any declaration of gas curtailment or supply emergency. By its terms, this notification does not extend to decisions to use other fuels for periodic testing or, indeed, for other reasons.

To resolve these inconsistencies, SOCMA urges EPA to revise the various regulatory definitions to simply track the preambular explanation quoted above.

Response: See response to comments EPA-HQ-OAR-2002-0058-2840.1, excerpt 12 and EPA-HQ-OAR-2002-0058-2875.1, excerpt 9 for use of back up fuels within Gas 1 units and appropriateness of 10% fuel use limit.
See response to comment EPA-HQ-OAR-2002-0058-2792.1, excerpt 223 for the 48 hour a year provision.

Commenter Name: Michael Potter
Commenter Affiliation: Goodyear Tire and Rubber Company
Document Control Number: EPA-HQ-OAR-2002-0058-3181
Comment Excerpt Number: 6

Comment: The liquid fuel subcategory applicability should be based on predominant usage.

EPA has not properly explained the selection of 10 percent liquid usage as the threshold for application of the liquid fuel subcategory. Goodyear believes that fuel subcategories logically should be based on the fuel prevalently used in the boiler. The extremely high control costs that would be required to comply with liquid fuel subcategory standards cannot be justified for boilers that will use natural gas most (i.e. more than 50 percent) of the time. This is particularly true insofar as Goodyear is not certain that technology exists to reliably achieve the proposed liquid fuel subcategory standards in its existing boilers, regardless of cost. Therefore, Goodyear believes the definition for the liquid fuel subcategory should be based on a 50 percent annual heat input threshold rather than 10 percent.

Response: See response to comments EPA-HQ-OAR-2002-0058-2840.1, excerpt 12 and EPA-HQ-OAR-2002-0058-2875.1, excerpt 9 for use of back up fuels within Gas 1 units and appropriateness of 10% fuel use limit.

Commenter Name: Gordon M. Smith
Commenter Affiliation: Mitsubishi Polyester Film, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2912
Comment Excerpt Number: 6

Comment: The list is based on the design fuel, however the only reasonable basis for assigning units into subcategories is what fuel they actually burn. Under the proposed definitions, units that burn gas and <10% liquid on an annual basis would appear to be in both a gas subcategory and the unit designed to burn oil subcategory. Both these definitions should be revised to clarify gas-fired units may burn liquid fuels up to 10% on an annual basis before changing to the liquid subcategory.

Response: See response to comments EPA-HQ-OAR-2002-0058-2840.1, excerpt 12 and EPA-HQ-OAR-2002-0058-2875.1, excerpt 9 for use of back up fuels within Gas 1 units and appropriateness of 10% fuel use limit.

EPA has revised the definitions of each subcategory to be based on the annual heat input of the fuel types. See final rule for modified definitions.

Commenter Name: Jeffery S. Hannapel
Commenter Affiliation: National Association for Surface Finishing
Document Control Number: EPA-HQ-OAR-2002-0058-2758.1
Comment Excerpt Number: 6

Comment: EPA's definition of natural gas needs to be broader to account for non-geological origins of natural gas such as landfill gas, biogas, and synthetic gas derived from coal.

Response: See response to comments EPA-HQ-OAR-2002-0058-2761.1, excerpt 15 and EPA-HQ-OAR-2002-0058-2702.1, excerpt 73 for the definition of natural gas needs to be broader to account for non-geological origins of natural gas.

Commenter Name: John Steber
Commenter Affiliation: Performance Fibers
Document Control Number: EPA-HQ-OAR-2002-0058-3174
Comment Excerpt Number: 6

Comment: Can a facility selectively use an alternative fuel in a boiler or process heater that is designed for its use, provided it maintains itself within the designated heat input threshold of the Gas 1 subcategory.

Response: See response to comments EPA-HQ-OAR-2002-0058-2840.1, excerpt 12 and EPA-HQ-OAR-2002-0058-2875.1, excerpt 9 for use of back up fuels within Gas 1 units and appropriateness of 10% fuel use limit.

Commenter Name: Shelley Schneider
Commenter Affiliation: Nebraska Department of Environmental Quality
Document Control Number: EPA-HQ-OAR-2002-0058-2820.1
Comment Excerpt Number: 6

Comment: Additionally, the definition of natural gas within the proposed NESHAP is inconsistent with the definition of natural gas found in 40 CFR Part 60 Subpart Db New Source Performance Standards (NSPS) for Industrial/Commercial/Institutional Steam Generating Units. The NSPS definition reads: 1) A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane; or (2) Liquefied petroleum gas, as defined by the American Society for Testing and Materials in ASTM D1835 (incorporated by reference, see §60.17); or (3) A mixture of hydrocarbons that maintains a gaseous state at ISO conditions. Additionally, natural gas must either be composed of at least 70 percent 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). At a minimum, the natural gas definitions should be consistent across federal air regulations.

Response: EPA has revised the definition of natural gas, consistent with the boiler NSPS.

Commenter Name: Richard Krock
Commenter Affiliation: The Vinyl Institute
Document Control Number: EPA-HQ-OAR-2002-0058-2944.1
Comment Excerpt Number: 7

Comment: Although gas-fired process heaters that burn liquid during periods of gas curtailment are regulated as gas fired process heaters, they should be allowed to burn other fuels up to ten percent (10%) of the time. VI supports the allowance for liquid firing during periods of curtailment for these heaters, as facilities need the flexibility to continue to operate during periods when gas supply is interrupted. The current proposed rule only allows for 2 days of operation on liquid fuels. VI strongly suggests that this should be changed to 10% of an operating year.

Response: See response to comment EPA-HQ-OAR-2002-0058-2792.1, excerpt 223 for the 48 hour a year provision.

Commenter Name: Michael Potter
Commenter Affiliation: Goodyear Tire and Rubber Company
Document Control Number: EPA-HQ-OAR-2002-0058-3181
Comment Excerpt Number: 9

Comment: The proposed regulations should clarify that the Gas 1 subcategory includes propane-fired boilers.

The proposed rules define the Gas 1 category through a series of reference documents. Goodyear finds this confusing, particularly for propane. Goodyear recommends that the rules be revised to specifically include propane as a Gas 1 subcategory fuel.

Response: See response to comment EPA-HQ-OAR-2002-0058-2849.1, excerpt 12 for Gas 1 subcategory and propane fired boilers.

Commenter Name: Ann W. McIver
Commenter Affiliation: Citizens Energy Group
Document Control Number: EPA-HQ-OAR-2002-0058-2875.1
Comment Excerpt Number: 9

Comment: In the preamble discussion, it appears that the EPA intended to provide that a natural gas-fired boiler that receives less than 10% of the annual heat-input from liquid fuels would be considered a natural gas-fired boiler for purposes of the regulations, and thus only subject to the annual tune-up requirements. However, the language found in the regulation appears to restrict the use of liquid fuels to periods of testing or supply curtailment. Unfortunately, it is possible to envision operating scenarios where "plant-side" equipment may require the use of liquid fuels to provide for maintenance of natural gas systems during periods that do not constitute emergencies as narrowly defined in the proposed rule. Citizens requests that EPA provide for these sorts of operating scenarios in the final rule by clearly providing that greater than 10% of the annual heat input for a combustion unit must come from liquid fuel before the requirements contained in that subcategory apply.

Response: See the final rule for definition of unit designed to burn gas 1. EPA has made limited allowances for burning of other fuels as noted in the definition.

Commenter Name: Jeffrey O'Hearn
Commenter Affiliation: Panolam Industries International Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2749.1

Comment Excerpt Number: 9

Comment: 63.7575: The definitions for Unit designed to burn gas 1, Unit designed to burn gas 2, and Unit designed to burn oil are a bit confusing. The particular confusion is how the 90% criteria for a gas 1 unit relates to the 48 hour requirement for oil fired units. For example, if a gaseous unit burns oil for more than 48 hours but still meets the 90% requirement, how would this unit be classified?

Response: See response to comment EPA-HQ-OAR-2002-0058-2792.1, excerpt 223 for the 48 hour a year provision.

A gas 1 unit burning liquid for more than 48 hours, if the oil was burned due to gas curtailment or supply emergencies would be considered to be a gas 1 unit. If the unit burned any oil for any other reason the unit would not be in the gas 1 subcategory.

Commenter Name: John Steber
Commenter Affiliation: Performance Fibers
Document Control Number: EPA-HQ-OAR-2002-0058-3174
Comment Excerpt Number: 9

Comment: PFI suggests the following modification for this definition:

"Units designed to burn natural gas/refinery gas (Gas 1) subcategory includes the collection of all existing industrial, commercial, and institutional boilers and process heaters that collectively burn at least 90 percent (if not specifically designed for dual-fuel use) or at least 70 percent (if specifically designed for dual-fuel fuel use) natural gas and/or refinery gas on a heat input basis on a 12-month rolling average. The heat input from fuel usage during periods of natural gas curtailment or supply interruption as defined under section 63.7575 does not have to be included in this assessment."

Response: See response to comments EPA-HQ-OAR-2002-0058-2840.1, excerpt 12 and EPA-HQ-OAR-2002-0058-2875.1, excerpt 9 for use of back up fuels within Gas 1 units and appropriateness of 10% fuel use limit.

Commenter Name: Edward E. Quick
Commenter Affiliation: Celanese International Corp
Document Control Number: EPA-HQ-OAR-2002-0058-2840.1
Comment Excerpt Number: 10

Comment: Process gases from petrochemical processes must be included in the definition of the Gas 1 Subcategory.

In the proposed rule, the Gas 1 Natural Gas/Refinery Gas (NG/RG) subcategory includes any boiler or process heater that burns at least 90 percent natural gas and/or refinery gas on a heat input basis on an annual average. The proposed rule does not define refinery gas and would seem to imply that the definition of refinery gas in 40 CFR §63.641 Subpart CC (National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries) should be used for purposes of the Boiler MACT rule.
Per Subpart CC, refinery fuel gas means a gaseous mixture of methane, light hydrocarbons, hydrogen, and other miscellaneous species (nitrogen, carbon dioxide, hydrogen sulfide, etc.) that is produced in the refining of crude oil and/or petrochemical processes and that is separated for use as a fuel in boilers and process heaters throughout the refinery. This definition includes gaseous mixtures produced in refineries and petrochemical processes but specifies the use of this gaseous fuel for refineries (only).
Since boilers and process heaters are located in refineries and petrochemical processes, the proposed rule should include process gases that meet certain specification, based on heat content. These process gases from petrochemical processes have similar compositions to those stated in the Subpart CC definition (e.g. methane, hydrogen, light hydrocarbons, and other components) that are used as fuel in boilers and process heaters.

Response: We appreciate the input from the commenter. We are not finalizing limits for units firing natural gas, refinery gas, and other Gas 1 fuels. See preamble for rationale for selecting a work practice for these units.

Commenter Name: Bruce A. Steiner
Commenter Affiliation: American Coke and Coal Chemicals Institute
Document Control Number: EPA-HQ-OAR-2002-0058-2849.1
Comment Excerpt Number: 11

Comment: The definition of gas-fired boilers includes those units burning gaseous fuels, which by further definition includes process gases (e.g., coke oven gas). However, the definition of gas-fired boiler is qualified by stating that gaseous fuels cannot be combined with any liquid fuel except during periods of gas curtailment, gas supply emergencies, or periodic testing on liquid fuels. Without clarification of that definition, the exemption for gas fired boilers is potentially negated.
While coke oven gas boilers are primarily designed to burn coke oven gas, usually with natural gas as a back-up fuel, they are sometimes supplemented with blast furnace gas or liquid fuels when the supply of coke oven gas from the coke oven process is interrupted due to operational difficulties or reduced operations necessitated by business conditions or when steam demands elsewhere in the plant that rely on steam from those boilers cannot be met by the available coke oven gas supply to the boilers. It is not clear from the definition of gas-fired boiler whether the terms gas curtailment and gas supply emergencies pertain to commercial natural gas supplies or can be interpreted to include occasions of curtailment and supply deficiencies from the process supplying the gas to the boiler. In the absence of clarifying language in the definition, the occasional use of liquid fuel would place these boilers (as well as any units using any liquid fuel, except in the stated circumstances) into a category that requires stringent emission limits, the

installation of costly emission control equipment, and testing, monitoring and recordkeeping obligations.
If the qualification of liquid fuel usage remains in the definition of gas-fired boiler, we suggest adding further clarifying language that is contained in the definition of a waste heat boiler in the Proposed Rule. As noted above, waste heat boilers are exempt from the rule. The waste heat boiler definition in the Proposed Rule is limited to units designed to use no more than 50% of the total heat input capacity of the unit with supplemental burners. We believe that the environmental and energy conservation benefits of using coke oven gas are comparable to the use of waste heat or blast furnace gas, both exempted under the Proposed Rule, and that the same provisions for using supplemental fuels should apply to units intended to utilize coke oven gas. Accordingly, applying the same rationale, we urge EPA to modify the gas-fired boiler exemption to include those units designed to use supplemental fuels up to 50% of the total heat input capacity of the unit.

Response: See response to comments EPA-HQ-OAR-2002-0058-2840.1, excerpt 12 and EPA-HQ-OAR-2002-0058-2875.1, excerpt 9 for use of back up fuels within Gas 1 units and appropriateness of 10% fuel use limit.

Commenter Name: Edward E. Quick
Commenter Affiliation: Celanese International Corp
Document Control Number: EPA-HQ-OAR-2002-0058-2840.1
Comment Excerpt Number: 12

Comment: The definitions of “units designed to burn liquid fuels” and “units designed to burn natural gas” are inconsistent, contradictory, and should be clarified as set forth below.
EPA should clarify the definitions in the proposed regulation for “units designed to burn liquid fuels” and “units designed to burn gas 2 (other).”
As an example, a boiler primarily operates on natural gas but also has the ability to burn distillate oil. On average, the total heat input of distillate oil to the boiler is 8% (oil is burned for capability testing, and during periods of natural gas curtailment); annual operating hours on fuel oil are 200 hours. If we wish to determine which emission limits the unit is subject to, we would perform the following analysis:

First, we refer to the definition of “units designed to burn gas 1 subcategory”. Based on the fact that the boiler in question burns 92% natural gas on an annual average heat input basis, we would rightly conclude that the boiler is subject to the Gas 1 requirements. However, we then look at the definition of “units designed to burn oil” subcategory. Based on this definition, the boiler in question could be classified a “unit designed to burn oil” since it does burn distillate oil (“any liquid fuel”), and total operation on oil exceeds 48 hours per year. This contradicts the conclusion reached when we applied the definition of “unit designed to burn natural gas” to the same unit.

Celanese is also concerned with the wording in the definition of “unit designed to burn oil” that apparently would allow a boiler that is primarily fueled by natural gas to remain in the Gas 1 category when oil is burned for periods of gas curtailment or supply emergencies, and for testing of liquid fuel systems. This clause is necessary, since the definition of Gas 1 allows limited use of liquid fuels (as long as total heat input remains below 10% on an annual basis). In any case, it is unclear whether “the combined total of 48 hours” condition applies to combined operation during curtailments, emergencies, and testing, or just to testing. Since periods of natural gas curtailment and supply emergencies routinely last for more than 48 hours, we believe EPA’s intent was only to restrict liquid fuels operations for testing purposes, and not during periods of curtailment and supply emergency. This can be clarified in the final rule by adopting revised definitions similar to those proposed below.

Similar confusion can arise for a unit that burns natural gas primarily (92% of annual heat input), and “other gases” (8% of annual heat input). Such a unit meets the definition of “unit designed to burn natural gas”, but also appears to meet the definition of “unit designed to burn gas 2”.
In contrast, consider the simplicity of the definition of “unit designed to burn coal,” which makes it quite clear that a boiler that burns natural gas 92% and coal 8% on an annual heat input basis is a Gas 1 unit and not a coal unit. We suggest that EPA use the same clear wording and logic (using a 10% triggering threshold) when establishing definitions for Gas 2 and liquid units to eliminate possible confusion and to create a consistent approach. We provide the following suggested wording for these definitions:

-Unit designed to burn oil subcategory includes any boiler or process that burns any liquid alone or at least 10 percent liquid on a heat input basis on an annual average in combination with biomass, coal, or gaseous fuel.

-Unit designed to burn gas 2 (other) subcategory includes any boiler or process heater that burns any gases other than natural gas or refinery gas alone or at least 10 percent other gas on a heat input basis on an annual average in combination with biomass, liquid, or gaseous fuel.

Response: The definition of gas curtailment as well as the 48-hour provision for periodic testing on liquid fuels has been revised in the final rule.
See response to comment EPA-HQ-OAR-2002-0058-2792.1, excerpt 223 for the 48 hour a year provision.

Commenter Name: Bruce A. Steiner
Commenter Affiliation: American Coke and Coal Chemicals Institute
Document Control Number: EPA-HQ-OAR-2002-0058-2849.1
Comment Excerpt Number: 12

Comment: ACCCI requests that EPA provide clarification that boilers firing liquefied petroleum gas (LPG) or propane-derived synthetic natural gas (SNG) as a backup fuel are considered a gas-fired boilers. We note that EPA proposes to incorporate ASTM D183503a to define "natural gas" for purposes of this regulation. It is important that any standard incorporated by the regulation be broad enough to encompass the use of propane (a constituent of LPG) as natural gas and not just mixtures. Most LPG mixtures include butane, which reduces the effectiveness of LPG at low temperatures, causing many facilities to substitute propane. Propane (and/or LPG) is mixed with air to create SNG, which should be specifically allowed to be considered as natural gas for purposes of this rule. LPG-based SNG is often used for emergency backup and EPA should make this point explicit in the final rule.

Response: In the final rule, propane was defined to be a type of natural gas.

Commenter Name: Bruce A. Steiner
Commenter Affiliation: American Coke and Coal Chemicals Institute
Document Control Number: EPA-HQ-OAR-2002-0058-2849.1
Comment Excerpt Number: 13

Comment: Finally, we request clarification that a boiler combusting landfill gas (or similar gaseous fuels derived from landfills or monofills) is considered a gas-fired boiler and not in the biomass category. ACCCI considers these fuels to fall under the definition of biogases, which are included in the definition of gaseous fuels, but we are aware that EPA has taken the position that gas derived from landfills is "biomass" under other rules. We seek clarification that for purposes of this rule it is not the agency’s intent to regulate boiler use of landfill or monofill gas, even if derived in whole or part from materials that might be defined as biomass.

Sulfuric acid is a volatile compound at flue gas temperatures that can partially condense and/or adsorb on the filter and collected solid PM.

Response: See response to comments EPA-HQ-OAR-2002-0058-2761.1, excerpt 15 and EPA-HQ-OAR-2002-0058-2702.1, excerpt 73 for the definition of natural gas needs to be broader to account for non-geological origins of natural gas.
Any gas that does not meet the definition of natural gas or refinery gas must be tested to ensure that it is below the specifications for mercury and hydrogen sulfide.

Commenter Name: Kevin M. Dempsey
Commenter Affiliation: American Iron and Steel Institute
Document Control Number: EPA-HQ-OAR-2002-0058-2998.1
Comment Excerpt Number: 15

Comment: Finally, we request clarification that a boiler combusting landfill gas (or similar gaseous fuels derived from landfills or monofills) is considered a gas-fired boiler and not in the biomass category. AISI considers these fuels to fall under the definition of biogases, which are included in the definition of gaseous fuels, but we are aware that EPA has taken the position that gas derived from landfills is "biomass" under other rules. We seek clarification that for purposes of this rule it is not the agency’s intent to regulate boiler use of landfill or monofill gas, even if derived in whole or part from materials that might be defined as biomass.

Response: See response to comments EPA-HQ-OAR-2002-0058-2761.1, excerpt 15 and EPA-HQ-OAR-2002-0058-2702.1, excerpt 73 for the definition of natural gas needs to be broader to account for non-geological origins of natural gas.

See response to comment EPA-HQ-OAR-2002-0058-2849.1, excerpt 13 for clarification that a boiler combusting landfill gas.

Commenter Name: Christopher S. Colman
Commenter Affiliation: Hovensa LLC
Document Control Number: EPA-HQ-OAR-2002-0058-2863.1
Comment Excerpt Number: 31

Comment: In setting a maximum 10% annual BTU threshold for the alternate fuel, EPA did not specify how this percentage should be calculated. HOVENSA asserts that the percentage should be based on an annual actual BTUs of the alternate fuel expressed as a percentage of the unit's RATED annual BTU capacity. This is the only way this threshold could be monitored by the facility to avoid unexpected category switching from gas to oil. It would allow the facility to calculate an equivalent barrels of fuel not to be exceeded in any given year, which can be monitored fairly easily. A threshold based on a number expressed as a percentage of the unit's actual total annual BTUs would be a constantly "moving target", making it nearly impossible to monitor and potentially causing units to go in and out of the oil category without warning. As discussed earlier, the BTU content of refinery gases can change significantly due to unpredictable events. Therefore, we propose that the language be clarified to specify a threshold for the alternate fuel expressed as a percentage of the unit's RATED annual BTU. HOVENSA also believes that the baseline for this determination should not be 1 year, it should be 5 or more years. At HOVENSA, units will be taken offline for major repairs and retrofits on a 3 to 5 year schedule which, when a fuel gas producing unit is taken offline, results in short term (20-40 days) increases in oil consumption at units in operation.
[Footnote 30: As noted above, HOVENSA disagrees that this is an appropriate dividing line, because the true dual fuel burners are designed to burn more than 10% of the alternative fuel. HOVENSA also does not support simply dropping co-fired or oil burning equipment into the Gas 1 category if the Gas 1 category is subject to numerical standards. That is because co-fired equipment will have different emissions characteristic both because of design and fuels used. Thus, numerical standards applicable to gas would not be MACT for this equipment.]

Response: See response to comments EPA-HQ-OAR-2002-0058-2840.1, excerpt 12 and EPA-HQ-OAR-2002-0058-2875.1, excerpt 9 for use of back up fuels within Gas 1 units and appropriateness of 10% fuel use limit.

EPA has adjusted the definition for each subcategory to specify how to calculate the annual heat input threshold to determine the subcategory for the unit. See the final rule for the revised definitions. EPA disagrees that MACT floors should not be established based on tests for units that co-fire fuels. If the test is based on at least 90 percent or more of a given fuel type EPA determined the data is accurate and representative of the other units in the subcategory.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 115

Comment: Work Practices Should Also Be Promulgated For Boilers and Process Heaters Combusting Petrochemical and Chemical Process Gases. All the arguments EPA makes to justify work practice requirements for natural gas/refinery gas apply to virtually all gases. If there are exceptions, (e.g., if further review of the Gas 2 data shows that emissions from coke oven gas are higher than emissions from other gases), then these fuels should be handled as exceptions to a general gas subcategory. Gas-fired units, relative to units firing other fuels, have the lowest emissions and pose the lowest risk of all the subcategories and thus the use of gas should be encouraged, rather than discouraged.

Response: We appreciate the input from the commenter. We are not finalizing limits for units firing natural gas, refinery gas, and other Gas 1 fuels. See preamble for rationale for selecting a work practice for these units.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 117

Comment: The characteristics of refinery gas and other gases such as petrochemical gas are extremely similar, which supports the inclusion of petrochemical gas into the Gas 1 category with natural gas and refinery fuel gas. These gases are clean burning fuels and are composed mainly of methane, ethane, and hydrogen.

Recently, an industry review of the composition data of refinery fuel gas and petrochemical gas was performed at member refineries and chemical plants on the gulf coast, utilizing data gathered between January and June 2010. There were approximately 11,200 sample data points used in the comparison. It should be mentioned that the data gathered was based on slightly different sampling methods depending on site/stream as explained below.

In cases where the site collects samples in the field manually, the analysis was performed in a lab. These samples were routinely collected at varying frequencies anywhere from weekly to three times a day. In cases where the site had an online analyzer on the fuel gas stream, the composition was collected and averaged over an hourly period before being recorded.

The comparison of the composition of refinery fuel gas and petrochemical gas indicated a very similar compositional footprint for these two gases (See submittal for Figure 10, comparison of composition). Methane (C1) and hydrogen (H2) are the dominant components for both gases. C2 compounds (ethane, ethylene, and acetylene) constitute the third major component for both gases. All other hydrocarbons, including C3, C4, C5, and C6+ constitute very small fraction of the composition. The remaining components (CO, CO_2, and N2) were very minor as well.

Combustion properties, including higher heating value, Wobbe index, and adiabatic flame temperature, of refinery fuel gas and petrochemical gas were also compared (See submittal for Figure 11 comparison of combustion properties). These properties were all similar for the two gases. The higher heating values were collected along with the composition data for refinery gas and petrochemical gas. The Wobbe indexes and adiabatic temperatures were calculated using the fuel gas composition data collected.

Higher heating value (HHV) is the amount of heat that a given quantity of fuel releases during combustion. The unit of measure for HHV is in the form of energy/quantity. One common unit is British Thermal Units (BTU) per standard cubic foot (Btu/scf). As shown in Figure 10 (see submittal for figure 10), the higher heating values for refinery fuel gas and petrochemical gas range similarly. They are all well above general threshold of HHV for good combustion.

The Wobbe index is a measure of the interchangeability of gases when they are used as a fuel. It compares the energy output of different gases during combustion. The Wobbe index is essential for analyzing the impact of a fuel changeover and is also a common specification of gas appliances. It is defined as higher heating value divided by square root of gas specific gravity. There are three "families" of fuel gases that have been internationally classified based on Wobbe Index. The Family 2 gas has a Wobbe index range of 1045 – 1474 Btu/scf. As shown in Figure 10 (see submittal for figure 10), the Wobbe indexes for both refinery gas and petrochemical gas fall in this range.

Adiabatic flame temperature is the temperature that results from a combustion process that occurs without any heat loss. It is affected by the fuel composition, fuel/air equivalence ratio, and fuel/air preheat temperature. Real flame temperatures are not as high as the adiabatic flame temperature, but the trends are comparable and representative of actual conditions. The peak adiabatic flame temperature for a given fuel and air occurs with a stoichiometric mixture (i.e. right amount of air to just get all fuel oxidized). High flame temperature is desirable for maximizing heat transfer and minimizing incomplete combustion product (e.g. CO). However, high flame temperature increases NOx formation.

The adiabatic flame temperatures at stoichiometric combustion were calculated for the refinery gas and petrochemical gas. As shown in Figure 11 (see submittal for figure 11), the adiabatic flame temperatures were also very similar for the two gases.

In conclusion, both the refinery gas and petrochemical gas are very similar in compositional nature and are extremely clean burning fuels. Both fuels should be categorized with natural gas in the Gas 1 category.

Response: We appreciate the input from the commenter. We are not finalizing limits for units firing natural gas, refinery gas, and other Gas 1 fuels. See preamble for rationale for selecting a work practice for these units.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 120

Comment: Similarly, natural gas fired units that supplement gaseous fuel with approved RCRA comparable fuels [40 CFR 261.38] should also be treated as Gas 1 boilers and subject only to work practices. Comparable fuels are secondary materials, such as alcohols, that have fuel value and characteristics (e.g., physical properties related to burning and levels of toxic constituents) comparable to or better than fuel oil. The chlorine, mercury, and metals contents of these fuels are limited to below constituent levels of fuel oil, so emissions are in effect already regulated. Therefore, these boilers should qualify for work practices as Gas 1 boilers.

Response: See response to comments EPA-HQ-OAR-2002-0058-2840.1, excerpt 12 and EPA-HQ-OAR-2002-0058-2875.1, excerpt 9 for use of back up fuels within Gas 1 units and appropriateness of 10% fuel use limit.

Any other gaseous fuels other than natural gas or refinery gas must demonstrate that they are at or below the specifications in the final rule for mercury and hydrogen sulfide. See preamble for discussion of gas specification. The 48-hour allowance or period of gas curtailment/gas supply emergencies applies to any liquid fuel, so any gas 1 boiler firing compareable liquid fuels for periodic testing or during allowable periods could still qualify as a gas 1 boiler.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 223

Comment: ACC Agrees That Gas Fired Boilers Burning Liquid During Periods Of Gas Curtailment Are Gas Fired Boilers, But Should be Allowed To Burn Other Fuels Up To 10% Of The Time. ACC supports the allowance for liquid firing during periods of curtailment for these boilers, as facilities need the flexibility to continue to operate during periods when natural gas supply is interrupted. However, we believe that the Gas 1 definition should be expanded to allow for additional operational flexibility. EPA has been very consistent throughout the proposal to use 10% as a threshold for movement from one subcategory to another. For example the most stringent – coal – includes units that burn at least 10% coal. The next – biomass – includes units that burn at least 10% biomass and less than 10% coal. The first sentence of the oil (liquid) subcategory includes any liquid fuel, but less than 10 % solid fuel. Therefore, it logically follows that a plain reading of the Gas 1 subcategory would be that EPA intended to include any unit that burns at least 90% gas and less than 10% of any other fuel. However, the second sentence in the oil (liquid) subcategory emphasized above is in contradiction with the Gas 1 definition by implying that any more than 48 hours (2 days) per year of liquid fuel firing would reclassify the unit into the liquid category. We recommend that EPA delete the sentence:

"Gaseous fuel boilers and process heaters that burn liquid fuel during periods of gas curtailment, gas supply emergencies or for periodic testing of liquid fuel not to exceed a combined total of 48 hours during any calendar year are not included in this definition.”

Based on the comments above and our previous comment that petrochemical and chemical plant process gases should be regulated under the Gas 1 subcategory, ACC proposes the following definition for Gas 1 boilers:

"Unit designed to burn Gas 1 (NG/RG) subcategory includes any boiler or process heater that burns at least 90 percent natural gas, propane, refinery gas, or off-gas streams for petrochemical and chemical plant processes on a heat input basis on an annual average and less than 10 percent of any solid or liquid fuel."

Response: In the final rule the 48-hour per year provision does not include periods of gas curtailment and supply emergencies. The 48-hour provision is specific to periods of testing. EPA has determined that only in these limited circumstances is a unit allowed to burn fuels other than gas 1 fuels and the gas 1 fuel category does not include all units that burn 90 percent gas 1 and 10 percent of any other fuel type.

Commenter Name: Michele E. Pugh
Commenter Affiliation: Flint Hills Resources, LP
Document Control Number: EPA-HQ-OAR-2002-0058-2910.1
Comment Excerpt Number: 3

Comment: The gas produced at FHR’s Port Arthur facility is classified as gas 2 since it is not produced within a refinery. However, component concentration information shows that it is similar to our refinery gas, i.e. mainly composed of methane and hydrogen (see Attachment 2 for a comparison of FHR’s refinery and chemical process gas). Chemical plant process gas should not be treated differently simply because it is produced outside of a refinery.

Response: We appreciate the input from the commenter. We are not finalizing limits for units firing natural gas, refinery gas, and other Gas 1 fuels. See preamble for rationale for selecting a work practice for these units.

Commenter Name: Dan F. Hunter
Commenter Affiliation: ConocoPhillips Company

Document Control Number: EPA-HQ-OAR-2002-0058-2867.1
Comment Excerpt Number: 6

Comment: Natural gas, refinery fuel gas, and petrochemical fuel gas are often integrated in refinery fuel gas systems. These gases have comparable composition and emission profiles and should be considered GAS-1 sources. The data underlying the GAS-1 and GAS-2 sources are not adequately described and defined to distinguish among these gases. EPA should classify all gases derived from hydrocarbon sources as being in the GAS-1 category.

Response: We appreciate the input from the commenter. We are not finalizing limits for units firing natural gas, refinery gas, and other Gas 1 fuels. See preamble for rationale for selecting a work practice for these units.

Commenter Name: John Steber
Commenter Affiliation: Performance Fibers
Document Control Number: EPA-HQ-OAR-2002-0058-3174
Comment Excerpt Number: 8

Comment: Should boilers and process heaters that are specifically designed for dual-fuel use be allowed more flexibility than the 90% threshold proposed in the definition — As discussed in Section IV.A in the preamble to this proposed rule (75 FR 32017), the definition of this subcategory is based on information collection activities which concluded that "boilers are designed based on a primary fuel type (and perhaps to burn a backup fuel) and can encounter operational problems if another fuel type that was not considered in its design is fired at more than 10 percent of the heat input to the boiler." PFI would tend to agree with this conclusion, however has concerns related to applying the same threshold to boilers and process heaters that are dual-fuel designed. The major concern is the potential but likely loss of any negotiating power related to the renewal of natural gas contracts with suppliers, which in turn could result in increased natural gas costs and the incentive for facilities to permanently switch from gas, which is considered a "clean" fuel, to their cheaper but "dirtier" alternative fuel (i.e., fuel oil). Therefore, PFI recommends that more flexibility be provided for the use of alternative fuels in boilers and process heaters that are specifically dual-fuel designed, such as a 70% threshold — a balance that would both allow facilities to maintain some of its negotiating power while at the same time discouraging abuse of the intent of this regulation.

Response: See response to comments EPA-HQ-OAR-2002-0058-2840.1, excerpt 12 and EPA-HQ-OAR-2002-0058-2875.1, excerpt 9 for use of back up fuels within Gas 1 units and appropriateness of 10% fuel use limit.

Subcategories: NG/RFG Metallurgical Furnaces

Commenter Name: Michael Palazzolo
Commenter Affiliation: Alcoa Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2967.1
Comment Excerpt Number: 1

Comment: Alcoa fully supports EPA's decision to establish a separate subcategory for "metal processing furnaces". Such furnaces are used in the aluminum industry to preheat metal for further processing and to heat treat metal to effect specific physical properties. A separate subcategory is appropriate for these furnaces because they differ significantly from other types of process heaters. Metal processing furnaces consist of large multi-zoned ovens with many small gas-fired burners. These furnaces are batch operated and typically have between 12 and 140 burners, with each burner having a capacity of 0.1 to 2 mmBTU/hr. The burners are fired into separate combustion chambers and are modulated between high-fire, low-fire and pulse (cycle on-off) to reach and control target temperatures in each furnace zone. The burners therefore operate over a wide turn-down range (burner output ranges from 100% to <10% of capacity) and remain in a "startup/shutdown" rather than steady-state mode most of the time.

Response: EPA agrees with the commenter that a separate subcategory is appropriate for these furnaces and has retained them in the final rule.

Commenter Name: N/A
Commenter Affiliation: Sierra Club, Clean Air Task Force, Earthjustice, and Natural Resources Defense Council
Document Control Number: EPA-HQ-OAR-2002-0058-3187.1
Comment Excerpt Number: 3

Comment: For the metal process furnace subcategory, the agency makes much of asserted differences in design and operation of these units compared with other industrial boilers and process heaters, id., arguing that these differences create distinct emissions characteristics justifying a separate subcategory (although in fact, EPA proposes work practice standards for this subcategory as well). What EPA really is doing here however, is creating subcategories in order to set up work practice standards that avoid the application of MACT-based emissions limits to a substantial part of the regulated industry. This is clearly unlawful.

Response: For the technical design reasons stated in response to comment EPA-HQ-OAR-2002-0058-2967.1, excerpt 1, and the policy reasons stated in the preamble EPA has maintained the metal process heater subcategory in the final rule and has also maintained the work practices for gas 1 type boilers and process heaters.

Commenter Name: Robert P. Strieter
Commenter Affiliation: The Aluminum Association
Document Control Number: EPA-HQ-OAR-2002-0058-2711.1

Comment Excerpt Number: 1

Comment: EPA proposes to include the 'Metal Process Furnaces' subcategory to distinguish natural gas-fired process heaters in the metals production industry from natural gas-fired process heaters used in other industries. The Association supports a separate subcategory for Metal Process Furnaces because these units have different design and operating characteristics, including variable heating regimes, intermittent burner operation and batch processing.

The Aluminum Association surveyed its members in the spring of 2009 to assess the types and number of Metal Process Furnaces that meet the definition of "Process Heater" under the Boiler MACT proposal. The data from the survey is summarized in the table that follows. Although not all furnaces were likely surveyed since only Aluminum Association members were included, the total of 253 furnaces represents a substantial portion of the aluminum Metal Process Furnaces operated in the U.S.

[See submittal for Table summarizing survey results]

Response: See reponse to comment EPA-HQ-OAR-2002-0058-2967.1, excerpt 1.

EPA acknowledges the comment and has retained the subcategory for metallurgical furnaces.

Commenter Name: Holly R. Hart
Commenter Affiliation: United Steelworkers Union
Document Control Number: EPA-HQ-OAR-2002-0058-2964.1
Comment Excerpt Number: 10

Comment: "Other Gas" Boilers

When EPA's calculation of the MACT floor for the "other gas" category is set against its calculation of the MACT floor that would apply to natural gas/ refinery gas boilers and to metal process furnaces if a work process standard were not proposed, it is clear that the MACT limits for the "other gas" boilers are comparable and in most cases lower than those that would apply to the exempted boilers. This suggests that on average "other gas" boilers perform as well as those exempted.

EPA cites the very high expense of bringing all the nearly 12,000 exempt boilers into compliance with its calculated MACT standards. But when these costs are broken down on a per-unit basis they are found to be comparable to the costs for the "other gas" units that are subject to MACT and in the same range (order of magnitude) as all the other units subject to the proposed rule.

Among the boilers now proposed for the work process standard are natural gas fired metal process furnaces. There is no evidence to suggest that metal process furnaces that burn fuels such as coke oven gas or blast furnace gas perform any worse than such furnaces that burn natural gas.

As such, they should be included in the current metal process furnace category or be treated the same as USW proposes “other gas” units be treated.

Response: EPA has modified the definition of the gas 1 subcategory in the final rule. See the preamble for discussion of the gas specification. Any boiler firing gaseous fuels that meet the specification will continue to qualify for work practice standards.

Commenter Name: Kevin M. Dempsey
Commenter Affiliation: American Iron and Steel Institute
Document Control Number: EPA-HQ-OAR-2002-0058-2998.1
Comment Excerpt Number: 16

Comment: The Metal Process Furnace Subcategory Should Include Furnaces That Combust Process Gases

The steel industry employs numerous metal process furnaces, including reheat furnaces, annealing furnaces, and heat treating operations. Some of these are direct-fired and are not covered by the rule, but others are indirect fired units that would classify them as process heaters. AISI supports the separate classification of “metal process furnaces,” which EPA found to be a “class of natural gas-fired process heaters that are designed and operated differently compared to typical process heaters.

The proposal correctly identifies the technological and operational issues that justify creation of a metal process heaters subcategory. However, the Proposed Rule further circumscribes that group by defining it to include only units that combust natural gas. Id. (“ [t]he process heaters used in metal processing are natural gas-fired and include annealing furnaces, preheat furnaces, reheat furnaces, aging furnaces, and heat treat furnaces”). While many metal process furnaces do use natural gas, others recycle (or can be used to efficiently recycle) process gas, such as coke oven gas, in order to reduce the amount of additional natural gas needed to operate these units.

The type of gas combusted in a given metal process heater has nothing to do with the technical and operational distinctions that render them unique, including the fact that they are designed with multiple burners in a single unit and rarely operate in a steady-state condition. Rather, those same findings apply equally to all metal process heaters combusting any gaseous fuel. As such, there is no legitimate basis for limiting this subcategory to natural gas-fired units and EPA should redefine this subcategory to include furnaces combusting any gaseous fuel.

Response: EPA acknowledges the comment and has retained the subcategory for metallurgical furnaces. EPA disagrees with the commenter and that only metal process heaters firing natural gas meet the definition of this subcategory. Metal furnaces firing solely natural gas qualify for the metal process heater subcategory.

Commenter Name: Kevin M. Dempsey
Commenter Affiliation: American Iron and Steel Institute
Document Control Number: EPA-HQ-OAR-2002-0058-2998.1
Comment Excerpt Number: 18

Comment: EPA Should Expand the Category of "Metal Process Furnace"

AISI requests that EPA revise the definition of metal process furnace to include the phrase "includes, but is not limited to" to acknowledge the fact that there may be other furnaces that should be excluded. Examples of such furnaces, in addition to annealing, preheat, reheat, aging and heat treat furnaces, include:

Stress relief furnaces, which are similar to aging and heat treat furnaces in that they are used to heat and cool metal to eliminate stresses from forging and similar activities.

Galvanizing/ galvanneal furnaces, which are similar to annealing furnaces in purpose and operation, but operate on a continuous (strip) rather than batch (coil) basis. Like annealing furnaces, these units fire sporadically as necessary to achieve an annealed consistency in the metal.

Alternatively, we request that EPA specifically add both of these units to the list of "metal process furnace" examples included in proposed section 63.7575.

Response: EPA has modfied the final rule to include homogenizing furnaces but has not modified the definition to include all other furnace types. Other determinations may be made on a case-by-case basis.

Subcategories: Other Gases (Gas 2)

Commenter Name: Arlington Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1779
Comment Excerpt Number: 38

Comment: A vast majority of our industry's boilers and process heaters rely on clean-burning fuel, whether it's natural gas, refinery gas, or gas from our petrochemical operations for the efficient operation of our facilities. However, we are not alone as many other industries, institutions, and government facilities also rely on these gaseous fuels to keep this nation going efficiently. EPA should continue to recognize the benefit of these clean fuels.

Response: We appreciate the input from the commenter. EPA has modified the definition of gas 1 and adopted a fuel specification. See the preamble for detailed discussion of the fuel

specification. We are not finalizing limits for units firing natural gas, refinery gas, and other Gas 1 fuels. See preamble for expansion of gas 1 definition and finalized work practice standards for all gaseous fuel boilers meeting the specifications for hydrogen sulfide and mercury.

Commenter Name: Don Grimm
Commenter Affiliation: Hood Industries, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2352
Comment Excerpt Number: 15

Comment: We also note that there is very little difference between the emissions from the top performing sources in the Gas 2 subcategory as compared with the Gas 1 subcategory. As a result, EPA would be justified in concluding that the Gas 1 and Gas 2 subcategories should be combined into a single gas-fired subcategory, which would be regulated by work practice standards for the reasons EPA explains in the preamble. At a minimum, units fired with process gases generated in chemical plants, pulp and paper plants, and similar operations should be included in the Gas 1 subcategory because the emissions data show very little difference in performance between units at these facilities and Gas 1 units.

Response: We appreciate the input from the commenter. EPA has modified the definition of gas 1 and adopted a fuel specification. See the preamble for detailed discussion of the fuel specification. We are not finalizing limits for units firing natural gas, refinery gas, and other Gas 1 fuels. See preamble for rationale for selecting a work practice for these units.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 108

Comment: We also note that there is very little difference between the emissions from the top performing sources in the Gas 2 subcategory as compared with the Gas 1 subcategory. As a result, EPA would be justified in concluding that the Gas 1 and Gas 2 subcategories should be combined into a single gas-fired subcategory, which would be regulated by work practice standards for the reasons EPA explains in the preamble. At a minimum, units fired with process gases generated in chemical plants, pulp and paper plants, and similar operations should be included in the Gas 1 subcategory because the emissions data show very little difference in performance between units at these facilities and Gas 1 units.

Response: We appreciate the input from the commenter. EPA has modified the definition of gas 1 and adopted a fuel specification. See the preamble for detailed discussion of the fuel specification. We are not finalizing limits for units firing natural gas, refinery gas, and other Gas 1 fuels. See preamble for rationale for selecting a work practice for these units.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 173

Comment: Some of our members are investigating projects where biomass will by pyrolized to create syngas, which will be burned in mill boilers in place of natural gas. Regulating this syngas as Gas 2 and subjecting it to stringent emission limits does nothing to incentivize innovative projects like these that will reduce a mill's reliance on fossil fuels.

Response: We appreciate the input from the commenter. EPA has modified the definition of gas 1 and adopted a fuel specification. See the preamble for detailed discussion of the fuel specification. We are not finalizing limits for units firing natural gas, refinery gas, and other Gas 1 fuels. See preamble for expansion of gas 1 definition and finalized work practice standards for all gaseous fuel boilers meeting the specifications for hydrogen sulfide and mercury. Based on the data in the record available for biogases most of these units fall below the specification and thus this revised definition should provide more flexibility to units burning these altnerative gaseous fuels.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 50

Comment: EPA proposes three subcategories for gas-fired units: non-metal boilers and process heaters firing natural gas and/or refinery gas (Gas 1); metal boilers and process heaters firing natural gas and/or refinery gas (metal process furnaces); and boilers and process heaters firing other gaseous fuels (Gas 2). We only deal with the Gas 1 and Gas 2 subcategories in these comments. EPA proposes a work practice standard for the Gas 1 subcategory and numerical emission limits for the Gas 2 subcategory. We have reviewed the information regarding HAP emissions from Gas 1 and Gas 2 fuels and made an assessment as to whether aggregation of all gas fuels under a work practice standard is technically sound and supported by the available data and our knowledge of the fuels that comprise those categories. Our review is included as Attachment B.

That review is divided into the following parts:

* HAP formation and emissions in gaseous fuel combustion
* Review of the available emissions data; and
* Discussion and Findings

From this technical review we reached the following conclusions.

* Pilot scale and field data studies support the conclusion that emissions of organic HAPs from gaseous fuels are not significantly affected by fuel type. The data gathered by EPA show that emissions of HCl, dioxins/furans, CO and PM from Gas 2 fuels are similar to or lower than those for Gas 1 fuels (neglecting CO data for four Gas 2 Process Gas fired units that strongly bias that data set).

* With the exception of mercury emissions from certain fuels, the data does not support treating Gas 1 and Gas 2 fuels differently to assure low emissions of HAPs. With the exception of mercury and HCl, combustion tuning to maintain operating conditions within the range for good combustion is expected to maintain low HAP emissions.

Recommendation: With very limited exceptions, the technical data developed by EPA indicate no HAP emission basis for treating Gas 1 and 2 differently. Thus, the proposed Gas 1 and Gas 2 subcategories should be combined.

Response: We appreciate the input from the commenter. EPA has modified the definition of gas 1 and adopted a fuel specification. See the preamble for detailed discussion of the fuel specification. We are not finalizing limits for units firing natural gas, refinery gas, and other Gas 1 fuels. See preamble for rationale for selecting a work practice for these units.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 247

Comment: Review of ICR Emissions Data

EPA has collected emissions data from boilers and process heaters firing a variety of gas fuels. These include fuels such as landfill gas and coke oven gas, and others that are less distinct that have been labeled as “Process Gas” and “Petrochemical Gas.” The HCl data population for Gas 1 and Gas 2 fuels not fired in metal furnaces consists of HCl emission test results for natural gas, refinery gas, coke oven gas (COG), biogas/natural gas, and landfill gas (Figure 2, top). Two of the three units listed as firing COG actually burn petroleum coke, not COG.

The 95% confidence intervals of the HCl data for each fuel can be used as a convenient visual indication of whether any observed differences in mean emissions among the different fuels are significant at the 95% confidence level. If the confidence intervals overlap, the differences can be not significant. This is rather simplified statistical analysis, but many of the data sets for individual fuels are too small for more sophisticated statistical methods such as t-tests to be meaningful. By inspection, it can be seen that the mean and confidence intervals for all of the Gas 2 fuels except biogas/natural gas lie within the confidence intervals for the Gas 1 subcategory, and within those for natural gas and refinery gas separately (Figure 2, bottom). The mean is slightly lower than that for natural gas. This indicates that the average HCl emissions from Gas 2 fuels are not significantly different from those for either natural gas or refinery gas.

The mean HCl emission for biogas/natural gas is much lower than those for the Gas 1 fuels, and the confidence interval is relatively narrow. No HCl emission data was found in the test report file provided by EPA for this unit, so they could not be verified. In previous versions of EPA‘s database, there were instances of phantom data caused by errors in extracting data from the electronic reporting tools (ERT and spreadsheets) which may be the case here. Assuming the data are correct, however, one would conclude there is no reason to create a separate subcategory for biogas/natural gas based on its HCl emissions compared to those from natural gas and refinery gas.

In the mercury data set, results are reported for natural gas, refinery gas, hydrogen, coke oven gas (COG), landfill gas, biogas/natural gas, and blast furnace gas (Figure 3). Two units firing petroleum coke are included in the COG group. Units firing at least 90% blast furnace gas are explicitly excluded from regulation under the proposed rule in 63.7491(j), but the results for one unit remain in EPA‘s database. Mercury emissions for landfill gas and biogas/natural gas units are at least as low as Gas 1 fuel units.

The dioxins and furans TEQ data set includes results for natural gas, refinery gas, landfill gas, biogas/natural gas, COG, blast furnace gas and heavy recycle/NG. Also, communications with the facility indicate that the heavy recycle/NG unit fires liquid fuel, and hence these data also should be excluded from the analysis. Comparing the remaining fuels, the confidence intervals for landfill gas, biogas/natural gas, and coke oven gas all overlap that for Gas 1 fuels. Thus, the differences in mean dioxins and furans TEQ emissions are not significantly different among these fuels.

The CO data set includes a wider variety of fuels and blends, including natural gas, refinery gas, COG, blast furnace gas, landfill gas, biogas/natural gas, biogas, natural gas/process gas, process gas, petrochemical process gas, natural gas/petrochemical process gas, and vent gas for APC (Figure 5). These fuels are not defined in terms of composition, heating value, or other characteristics so it cannot be said to what degree they are truly different from each other. Among these, the COG data set includes a number for petroleum coke fired units. With the exception of Process Gas, all of the Gas 2 fuels lie within or below the range of CO produced by Gas 1 fuels. The mean and variability of CO within the Process Gas group is substantially greater than the other fuels, with the upper range extending into the thousands of ppm. The mean and confidence intervals are strongly biased by three units at one facility and one unit at a second facility that have an average CO concentration of 2570 ppm (12 data points). Because there are many other units firing Process Gas with lower emissions, it seems likely that CO emissions are high due to characteristics of the units in which they are fired. The remaining 232 of 244 CO data points within this fuel group fall below approximately 200 ppm, with a mean of 13 ppm. This compares favorably with, even lower than, CO levels from Gas 1 fuels.

Mean filterable PM emissions for all Gas 2 fuels fall within the 95% confidence bounds for either natural gas or refinery gas, with the exception of data for one unit reportedly burning COG with natural gas that is much higher than the other fuels (Figure 6). This consists of a single data point from a 1995 test, providing no information on variability, so its representativeness must be questioned.

It should be noted that data sets for several of the fuel groups are quite small, with fewer than 10 data points. For such small data sets, confidence intervals are not reliable indicators of the full population, so it is difficult to say with certainty that these fuels do or don't produce emissions similar to the other fuels. In most cases, this is an argument for aggregating these fuel groups with other groups that have larger populations to produce a statistically valid analysis.

Discussion and Findings

The ICR data show that average emissions of HCl, dioxins/furans TEQ, CO and PM emissions among various Gas 2 fuels that do not combust process vent gas containing chlorine are at least as low those for Gas 1 fuels (neglecting CO data for four Gas 2 Process Gas fired units that strongly bias the mean CO level of that relatively large data set).

The data indicate that in most cases the mean emission levels for Gas 2 fuels are within the range and confidence intervals for individual Gas 1 fuels, suggesting that differences in gas fuel characteristics to not have a first order impact on HAP emissions. The presence of a small number of very high outliers among a large set of CO data for Process Gas suggests that system characteristics may have greater significance than fuel characteristics for this group. This clearly indicates poor combustion conditions, and an opportunity for CO emission reduction via combustion improvement.

Response: We appreciate the input from the commenter. EPA has modified the definition of gas 1 and adopted a fuel specification. See the preamble for detailed discussion of the fuel specification. We are not finalizing limits for units firing natural gas, refinery gas, and other Gas 1 fuels. See preamble for rationale for selecting a work practice for these units.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 259

Comment: The vast majority of Gas 2 units in the ICR CO data set have no emission controls (Figure 1). All but two units in the floor have no controls. Data for units with no controls also span the full range of reported CO emissions. Four units are equipped with flue gas recirculation (FGR) for NOX emissions control. FGR reduces NOX by recirculating cooled flue gas from the boiler/heater outlet into the combustion zone via mixing with the combustion air or through injection ports, thereby reducing peak flame temperatures and oxygen availability. There is one unit reported with a cyclone, which is a boiler that burns biogas produced from gasification of rice hulls and the fuel contains ash resulting from inorganic matter in the gasifier feed. One unit is reported to have a fabric filter with limestone injection; this unit is categorized as firing coke oven gas, but review of the ICR documentation shows this is actually fired with petroleum coke, a solid fuel. Although four units with FGR span the lower decade of CO emissions, there is no reason to expect FGR should result in lower CO emissions; in fact, increased CO is often reported when FGR is added since it decreases combustion temperatures, oxygen availability and furnace residence time which inhibit complete CO oxidation.

Response: See response to comment EPA-HQ-OAR-2002-0048-2632.1, excerpt 19 for inadequacies of the Gas 2 dataset.

EPA did not base its floor calculations on the controls installed in each subcategory but instead based on the emission performance of each of the units in the subcategory. EPA has also adjusted several units firing petroleum coke from the gas 2 to solid fuel subcategory based on comments received during the public comment period.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 262

Comment: The Gas 2 data set for filterable PM includes 14 units. Six of the units are fired on blast furnace gas (excluded from the rule). One unit is co-fired with liquid fuel. All but two units are reported to have no controls (Figure 4). The two units with controls both with limestone injection/fabric filter are fired with petroleum coke rather than a gas fuel.

Response: See response to comment EPA-HQ-OAR-2002-0048-2632.1, excerpt 19 for inadequacies of the Gas 2 dataset.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 265

Comment: The Gas 2 data set for HCl includes data for units with no controls and limestone injection/fabric filter (Figure 6). A single unit with no controls comprises the MACT floor. Investigation of the test reports and correspondence from the facility submitted to EPA confirm that the two units with limestone injection/fabric filter (EPA #4 and #8) are actually fired on petroleum coke, not coke oven gas. The single unit comprising the MACT floor (EPA #1) was found to fire a liquid fuel. Therefore, these units should be removed from the MACT floor analysis for Gas 2. This leaves HCl data for only five Gas 2 units, all of which have no controls. Thus, no conclusions with respect to HCl control technology can be drawn from these data.

Response: See response to comment EPA-HQ-OAR-2002-0048-2632.1, excerpt 19 for inadequacies of the Gas 2 dataset.

Commenter Name: John C. deRuyter
Commenter Affiliation: DuPont
Document Control Number: EPA-HQ-OAR-2002-0058-2793.1
Comment Excerpt Number: 6

Comment: Hydrogen fueled off-gases

DuPont believes that process off-gases derived from natural gas or petrochemical feedstocks that have even lower heating values due to their hydrogen content than typical hydrocarbon gases also provide useful combustion energy and should be treated similarly to Gas 1 units. These process gases provide stable combustion characteristics and typically have low contaminant content due to the nature of the processes. The EPA hydrogen fueled flare document- Basis and Purpose Document on Specifications For Hydrogen-Fueled Flares, Emission Standards Division, U.S. Environmental Protection Agency Office of Air Radiation, Office of Air Quality Planning Standards, March 1998, documents the basis for establishing minimum hydrogen content for unsupported flare combustion. The testing documented established the minimum hydrogen content of 8% by volume as that proven adequate for sustained combustion without support fuel (nonassisted flare operation).

As noted in the referenced document (also submitted for reference), hydrogen has a lower heat content than organics commonly combusted in flares meeting the prior existing flare specifications and cannot, therefore, be used to satisfy prior control requirements. However, since the combustion of hydrogen is different than the combustion of organics, and the test report demonstrates a destruction efficiency greater than 98 percent, the EPA believes that hydrogen-fueled flares meeting the recommended specifications will achieve a control efficiency of 98 percent or greater. This level of control is equivalent to the level of control achieved by flares meeting the prior existing specifications. In addition to achieving the same destruction efficiency of VOC or organic HAP, these recommended specifications have the added advantage of reducing the formation of secondary pollutants; since the combustion of supplemental fuel would not be required by hydrogen-fueled flares to meet the existing flare specifications. Therefore, DuPont recommends a similar approach be used to establish 8% by volume as a minimum hydrogen content in hydrogen fueled process gases as a criterion that allows its use as a fuel in boilers and process heaters under the Boiler MACT rule and allow consideration as Gas 1 with a work practice MACT approach.

Response: We appreciate the input from the commenter. EPA has modified the definition of gas 1 and adopted a fuel specification. See the preamble for detailed discussion of the fuel specification. We are not finalizing limits for units firing natural gas, refinery gas, and other Gas 1 fuels. See preamble for rationale for selecting a work practice for these units.

Commenter Name: Jeffrey R.Klieve
Commenter Affiliation: Monsanto Company
Document Control Number: EPA-HQ-OAR-2002-0058-2754.1
Comment Excerpt Number: 8

Comment: Monsanto requests that USEPA consider including other gaseous fuels that do not contain HAPs in the Gas 1 category. Monsanto operates a natural gas-fired boiler capable of burning up to 70% hydrogen gas, which is recovered from an on-site chemical process. The hydrogen stream contains no HAPs. Burning this hydrogen stream displaces the burning of natural gas, which does contain HAPs such as BTEX at low level concentrations.

Including gaseous fuels such as hydrogen in the Gas 2 category subjects these boilers to requirements which achieve no further reduction of HAPs to the environment, yet require the source to comply with extensive initial and perennial performance testing, recordkeeping, fuel analyses, and CO CEMS for units 100 MMBtu/hr or greater.

Response: We appreciate the input from the commenter. EPA has modified the definition of gas 1 and adopted a fuel specification. See the preamble for detailed discussion of the fuel specification. We are not finalizing limits for units firing natural gas, refinery gas, and other Gas 1 fuels. See preamble for rationale for selecting a work practice for these units.

Commenter Name: Dave Copeland
Commenter Affiliation: Praxair Inc
Document Control Number: EPA-HQ-OAR-2002-0058-3141
Comment Excerpt Number: 1

Comment: A hydrogen plant's tail gas should be regulated similar to natural gas. Tail gas should not be regulated as "other gas".

EPA established emission limitations and work practice standards for 11 subcategories in the proposed Boiler MACT regulations. Units designed to burn "other gas" is one of the 11 categories (63.7499(a)(10)) but there is no definition in 40 CFR 63.7575 even though 63.7499(b) states "Each subcategory is defined in §63.7575". This will drag all the units that burn gaseous material that does not meet natural gas or refinery gas into the "other gas" sub category (63.7499(a)(10)) and be required to comply with stringent Table 4 emission standards for particulate matter and carbon monoxide limits that apply.

Response: We appreciate the input from the commenter. EPA has modified the definition of gas 1 and adopted a fuel specification. See the preamble for detailed discussion of the fuel specification. We are not finalizing limits for units firing natural gas, refinery gas, and other Gas 1 fuels. See preamble for rationale for selecting a work practice for these units.

Commenter Name: Mark Calmes
Commenter Affiliation: Archer Daniels Midland Company
Document Control Number: EPA-HQ-OAR-2002-0058-2927.1
Comment Excerpt Number: 2

Comment: EPA did not take into account in the establishment of the Gas 2 MACT Floors the extreme diversity of Gas2 fuels and the units in which they are combusted. The proposed limit for CO of one ppm is unattainable for most units burning process gas. If it were attainable, it would not represent the point of optimum combustion efficiency for most boilers and process heaters, thereby raising emissions of other pollutants.

Response: See response to comment EPA-HQ-OAR-2002-0048-2632.1, excerpt 19 for inadequacies of the Gas 2 dataset.

See the preamble for how the CO floors were adjusted to incorporate instrument measurement error and a revised expected dataset of units in the gas 2 subcategory.

Commenter Name: Dave Copeland
Commenter Affiliation: Praxair Inc
Document Control Number: EPA-HQ-OAR-2002-0058-3141
Comment Excerpt Number: 2

Comment: EPA established PM and CO limits for boilers/process heaters as a surrogate to metal HAPs and Organic HAPs. Units burning gaseous fuels similar in nature for organic components and metal components as natural gas should be in the same category as natural gas. Unfortunately, in the proposed rule, units burning gaseous fuels similar in nature for organic components and metal components as natural gas still have to comply with the stringent limits of the "other gas" category.

For example, tail gas produced in hydrogen production process is similar to natural gas and unfairly needs to comply with the stringent limits of the "other gas" category. Praxair is a major producer of hydrogen utilized in the refinery, chemical and electronics industries. Modern, large-scale hydrogen plants that use natural gas as a feedstock are the primary means of meeting the growing industry demand for hydrogen.

A modern steam methane reformer (SMR) based hydrogen plant consists of four primary subsystems (see Figure 1). Natural gas is used both as a feedstock and as a fuel. The natural gas stream is split, and the majority is used as process feed, which is compressed and desulfurized before entering the reformer reactor tubes. Gas _leaving the reformer enters a high-temperature shift reactor, where carbon monoxide (CO) is reacted with steam.to produce additional hydrogen. After cooling, hydrogen-rich gas from the shift reactor is processed by a Pressure Swing Absorption (PSA) unit for purification to product hydrogen specifications. The PSA tail gas (Tail

Gas), consisting of unreacted methane, CO, nitrogen, and unrecovered hydrogen, is recycled for mixing with natural gas and used as fuel in the reformer furnace. This clean-burning "tail gas" provides most of the reformer fuel (-75-90%), the emissions are,much lower than if the same amount of heating were provided by natural gas (because of the desulfurization step), which itself is considered to be "clean-burning". It should be noted that this "clean burning" characteristic of hydrogen plants has been recognized by EPA before in New Source Performance Standards for Petroleum Refineries (40 CFR Part 60 Subparts J and Ja) as inherently low in sulfur and therefore exempt from sulfur monitoring. [See submittal for Figure 1. Steam Methane Reformer Process Flow Diagram.]

The SMR is a process heater as defined by the proposed rule. Depending on where the hydrogen plant is located, the tail gas would fall under either a natural gas/refinery gas category or as an "other gas" category. If the hydrogen plant is located and regulated as part of a refinery, the tail gas would be viewed as a refinery gas and the combined stream of natural gas and tail gas would be regulated the same. If the hydrogen plant is not part of a refinery, the tail gas would be considered an "other gas" as per the proposed rule. This puts the natural gas and the tail gas in two different regulatory categories which increases the complexity of compliance.

Since tail gas is derived from natural gas, is made up of methane, CO, CO_2, nitrogen and hydrogen and is a clean burning fuel, comparable to natural gas, it would seem more appropriate for tail gas to be regulated similar to natural gas rather than as "other gas".

Recommendation: Include Hydrogen Plant Tail Gas or similar process gases derived from natural gas processing in the same subcategory as 63.7499(a)(9). This can be done by revising 63.7499(a) (9) as "Units designed to burn natural gas/ refinery gas/ other gas derived from natural gas/refinery gas processing. Also including a definition for other gas derived from natural gas/refinery gas processing.

Response: We appreciate the input from the commenter. EPA has modified the definition of gas 1 and adopted a fuel specification. See the preamble for detailed discussion of the fuel specification. We are not finalizing limits for units firing natural gas, refinery gas, and other Gas 1 fuels. See preamble for rationale for selecting a work practice for these units.

Commenter Name: Mark Calmes
Commenter Affiliation: Archer Daniels Midland Company
Document Control Number: EPA-HQ-OAR-2002-0058-2927.1
Comment Excerpt Number: 3

Comment: The limits for other MACT pollutants are not well established due to the inadequacies of the database, and the proposed requirement to test for them periodically would be a disincentive for the use of process gas. For example, EPA does not have enough data on combustion of anaerobic digester gas to differentiate it from natural gas. As such, classification of anaerobic digester gas as Gas 2 is unreasonable.

Response: See response to comment EPA-HQ-OAR-2002-0048-2632.1, excerpt 19 for inadequacies of the Gas 2 dataset.

EPA revised is definition of gas 1 and based its gas 2 floor on all gas data that were not demonstrated to meet the specifications. Based on the data available in the record biogas meets the specifications of the final rule. Each gaseous fuel must test its fuel type to demonstrate that it meets the specification.

Commenter Name: Chelly Reesman
Commenter Affiliation: JR Simplot Company
Document Control Number: EPA-HQ-OAR-2002-0058-3162
Comment Excerpt Number: 4

Comment: Fuels Subject to the Proposed Rule
Simplot generates biogas from wastewater treatment facilities associated with potato processing. This gas is used to supplement natural gas or hydrogen fuel in our boilers. Biogas is one of the listed types of gaseous fuels. Since it is not a refinery gas or a natural gas, boilers firing biogas fall under the category "Unit designed to burn gas 2 (other)". Please confirm our understanding that biogas fueled units are subject to the emission limits specified for "Units designed to burn other gases".

Response: We appreciate the input from the commenter. EPA has modified the definition of gas 1 and adopted a fuel specification. See the preamble for detailed discussion of the fuel specification. We are not finalizing limits for units firing natural gas, refinery gas, and other Gas 1 fuels. See preamble for expansion of gas 1 definition and finalized work practice standards for all gaseous fuel boilers meeting the specifications for hydrogen sulfide and mercury. Based on the data in the record available for biogases most of these units fall below the specification and thus this revised definition should provide more flexibility to units burning these altnerative gaseous fuels.

Commenter Name: Holly R. Hart
Commenter Affiliation: United Steelworkers Union
Document Control Number: EPA-HQ-OAR-2002-0058-2964.1
Comment Excerpt Number: 11

Comment: A large fraction of “other gas” units are biogas units. These include boilers where waste gasses such as those from treatment ponds are used as fuel instead of allowed to be vented directly to the environment. All of EPA’s reasoning that it applied to the natural gas/refinery gas units and the metal process furnaces applies equally well to the “other gas” boilers.

Response: We appreciate the input from the commenter. EPA has modified the definition of gas 1 and adopted a fuel specification. See the preamble for detailed discussion of the fuel specification. We are not finalizing limits for units firing natural gas, refinery gas, and other Gas 1 fuels. See preamble for rationale for selecting a work practice for these units.

Commenter Name: Russ A. Wozniak
Commenter Affiliation: Dow Chemical Company
Document Control Number: EPA-HQ-OAR-2002-0058-2632.1
Comment Excerpt Number: 19

Comment: We believe the EPA's estimate of 199 sources in the Gas2 category is extremely low. Dow has approximately 30 sources that may be in this category and we suspect that the true number of total sources in this category is closer to 1,000 - 2,000. Thus, we urge EPA to reconsider the entire proposal for the "Other Gases" category and to establish work practice standards in lieu of concentration based emission standards at this time.

In addition, it should also be noted that the boiler exhaust temperatures are much lower than design during low load conditions, such as stand-by operations. Thus, the use of an oxidation catalyst to reduce CO emissions to < 1 ppmv will not be effective during times of low load operation.

Response: EPA has based its Gas 2 inventory and its revised Gas 2 floors on data made available to the Agency in two separate ICRs as well as voluntariy data submitted during the public comment period. Based on the revised definitions of gas 1 to include the gas specification EPA also expects more units to qualify as gas 1 instead of gas 2.

Commenter Name: Shelley Schneider
Commenter Affiliation: Nebraska Department of Environmental Quality
Document Control Number: EPA-HQ-OAR-2002-0058-2820.1
Comment Excerpt Number: 4

Comment: Biogas is a renewable fuel with similar characteristics to natural gas. Many facilities in the United States are combusting landfill, digester, and other biogases in lieu of combusting traditional fossil fuels. NDEQ encourages facilities to combust biogas and believes the proposed standards will provide a disincentive to burning biogas.

Response: EPA has modified the definition of gas 1 and adopted a fuel specification. See the preamble for detailed discussion of the fuel specification. Based on the data in the record available for biogases most of these units fall below the specification and thus this revised definition should provide more flexibility to units burning these altnerative gaseous fuels.

Commenter Name: Jerry Osheka
Commenter Affiliation: PPG Industries
Document Control Number: EPA-HQ-OAR-2002-0058-2938.1
Comment Excerpt Number: 2

Comment: PA Should Adopt the Work Practices for Gas 2 Fuel Boilers as the MACT Floor. All the arguments EPA makes to justify work practice requirements for natural gas/refinery gas apply to virtually all gases. If there are exceptions, (e.g., if further review of the Gas 2 data shows that emissions from coke oven gas are higher than emissions from other gases), then these fuels should be handled as exceptions to a general gas subcategory. Gas-fired units, relative to units firing other fuels, have the lowest emissions and pose the lowest risk of all the subcategories and thus the use of gas should be encouraged, rather than discouraged.

Integrated chemical plant sites strive to be as energy efficient as possible. One way to promote energy efficiency is to capture off-gas from petrochemical and chemical plant off-gas streams and re-use these streams as fuel in a variety of combustion sources. Plant sites are designed to use many types of “Gas 2” streams as a fuel in order to have energy efficient operations. If Gas 2 fuels are subjected to stringent emission limits instead of work practice requirements, the rule likely will force facilities to dispose of process off-gases in other types of combustion sources including flares, which results in more natural gas being used, inefficient operations, and an increase in greenhouse gas emissions.
The characteristics of refinery gas and other gases such as petrochemical gas are extremely similar, which supports the inclusion of petrochemical gas into the Gas 1 category with natural gas and refinery fuel gas. These gases are clean burning fuels and are composed mainly of methane, ethane, and hydrogen.

Response: We appreciate the input from the commenter. EPA has modified the definition of gas 1 and adopted a fuel specification. See the preamble for detailed discussion of the fuel specification. We are not finalizing limits for units firing natural gas, refinery gas, and other Gas 1 fuels. See preamble for rationale for selecting a work practice for these units.

Commenter Name: Barry Christensen
Commenter Affiliation: Occidental Chemical Corp
Document Control Number: EPA-HQ-OAR-2002-0058-2848.1
Comment Excerpt Number: 3

Comment: The Gas 1 subcategory should include boilers and process heaters fired with hydrogen gas. Hydrogen is generated as a byproduct of our Chlor-Alkali manufacturing process. After purification of the hydrogen, OCC sells it as a commercial product to industrial and medical gas manufacturing facilities or uses it onsite as a fuel. Two of our locations fire hydrogen in combination with natural gas in their boilers. Other OCC locations burn hydrogen in their waste heat boilers. Attachment A includes data comparing the composition of hydrogen to natural gas, derived from fuel gas samples collected during a November 2002 stack test at our Taft, Louisiana Chlor-Alkali plant. The second set of data includes a comparison of hydrogen to natural gas from a September 2007 stack test from our LaPorte, Texas Chlor-Alkali facility. The third set of attached data includes more recent natural gas analyses at this same plant. In addition, our Wichita, Kansas facility tested its hydrogen in June of 2010. Sample results indicated less that 10 ppb (the R&D lab limit of detection) of methylene, chloride, chloroform, carbon tetrachloride, 1- bromo2-chloroethane, toluene and perchloroethylene. Our hydrogen-producing ChlorAlkali facilities also routinely analyze their raw material brine for mercury and the results are routinely less than the applicable limits of detection. Finally, hydrogen analyses taken in 1997 at our Ingleside, Texas Chlor-Alkali facility indicated chloride values less than 8 ppb. Therefore, historic data indicates that firing this byproduct hydrogen has minimal potential to generate HCL, Dioxin/ Furans, or mercury emissions. Therefore, hydrogen is a cleaner burning fuel than natural gas and hydrogen should not be included in the "Other Gas, Gas 2 category." We respectfully request that EPA amend the final rule to include hydrogen gas-fired boilers and process heaters in the Gas 1 subcategory.

Response: We appreciate the input from the commenter. EPA has modified the definition of gas 1 and adopted a fuel specification. See the preamble for detailed discussion of the fuel specification. We are not finalizing limits for units firing natural gas, refinery gas, and other Gas 1 fuels. See preamble for rationale for selecting a work practice for these units.

Commenter Name: Jerry Osheka
Commenter Affiliation: PPG Industries
Document Control Number: EPA-HQ-OAR-2002-0058-2938.1
Comment Excerpt Number: 3

Comment: EPA Should Classify the Combustion of Hydrogen Gas as a Gas 1 Fuel from Chlor-Alkali By-Product Production. The byproduct production of hydrogen gas from chlor-alkali production facilities is estimated at 389 thousand metric tons of hydrogen annually which is equivalent to the annual fuel consumption of 1.9 million light-duty hydrogen vehicles. The process itself involves the electrolysis of salt water which, in combination with other process steps,splits salt (NaCl) in solution into sodium hydroxide (NaOH), chlorine gas and hydrogen gas. In this process, hydrogen is a byproduct produced in a comparatively pure form.

This hydrogen byproduct can be sold directly into commerce where it has a myriad of uses or used to produce hydrochloric acid (HCl). One of the major uses however takes of Hydrogen's heating value using it as a high quality fuel to produce electricity or steam. The chlorine chemistry industry has long employed cogeneration, an energy efficiency attained through the coproduction of electricity and process heat (also called combined heat and power or CHP) from a plant that is located at the chemical manufacturing facility. Significant efficiencies are gained from the productive use of the by-product heat, usually in the form of steam. While the efficiency gains can vary widely among individual sites, at its peak co-generation can be over 70 percent efficient.

The combustion of Hydrogen does not emit carbon dioxide or other greenhouse gases thus should be considered a "clean fuel". Recovering and burning the hydrogen also preserves existing reserves such as coal, oil and natural gas. Considering the vital and growing role of energy in global economic and environmental issues, the chlorine industry is likely to increase its use of co-generation. Because hydrogen is comparatively pure and considered a clean fuel, EPA should classify the cogeneration use of hydrogen fuel as a Gas 1 fuel.

Response: We appreciate the input from the commenter. EPA has modified the definition of gas 1 and adopted a fuel specification. See the preamble for detailed discussion of the fuel specification. We are not finalizing limits for units firing natural gas, refinery gas, and other Gas 1 fuels. See preamble for rationale for selecting a work practice for these units.

Commenter Name: Christopher Peters
Commenter Affiliation: Low Carbon Synthetic Fuels Association
Document Control Number: EPA-HQ-OAR-2002-0058-2942.1
Comment Excerpt Number: 3

Comment: The LCSFA urges EPA to adopt a definition of natural gas under Section 63.675 that explicitly treats syngas equally as compared to natural gas and refinery gas. We suggest that EPA adopt a definition similar to that used in the Subpart YYYY standards for stationary combustion turbines. If EPA is concerned about the purity of syngas, it could require that syngas meet minimum specifications as it did in the Part 261 hazardous waste regulations. As syngas for the FT process must be extremely clean to avoid poisoning the FT catalyst, syngas used in boilers at integrated biorefineries would meet these specifications.

Response: We appreciate the input from the commenter. EPA has modified the definition of gas 1 and adopted a fuel specification. See the preamble for detailed discussion of the fuel specification. We are not finalizing limits for units firing natural gas, refinery gas, and other Gas 1 fuels. See preamble for expansion of gas 1 definition and finalized work practice standards for all gaseous fuel boilers meeting the specifications for hydrogen sulfide and mercury. Based on the data in the record available for biogases most of these units fall below the specification and thus this revised definition should provide more flexibility to units burning these altnerative gaseous fuels.

Commenter Name: John T. Heard
Commenter Affiliation: The Virginia Coal Association
Document Control Number: EPA-HQ-OAR-2002-0058-2953.1
Comment Excerpt Number: 4

Comment: A work practice standard should be applied to integrated has combined cycle units

Boilers and process heaters that burn refinery gas and natural gas emit very low levels of HAPs. As a result, emissions from these units pose little risk to public health and safety. EPA has, therefore, proposed to set a work practice standard for existing gas-fired ("Gas 1") industrial boilers and process heaters, rather than specific emissions limitations. Integrated Gas Combined Cycle (IGCC) units employ the use of a gasifier to convert coal into gas and then remove impurities from the resulting gas before combusting it in a gas turbine. This process of removing impurities from coal-derived gas results in emission levels of particulate matter, sulfur dioxide, and mercury from IGCC units that compare to those of other gas-fired units. Therefore, such coal-derived gas should he added to the Gas 1 category of fuels, and IGCC units should be subject to work practice standards rather than strict MACT floors. Applying such a standard would also incentivize the development of IGCC technology, which, with additional research, development and deployment, could become a promising option for reducing CO_2 emissions in coal-fired industrial boilers and process heaters.

Response: We appreciate the input from the commenter. EPA has modified the definition of gas 1 and adopted a fuel specification. See the preamble for detailed discussion of the fuel specification. We are not finalizing limits for units firing natural gas, refinery gas, and other Gas 1 fuels. See preamble for expansion of gas 1 definition and finalized work practice standards for all gaseous fuel boilers meeting the specifications for hydrogen sulfide and mercury. Based on the data in the record available for biogases most of these units fall below the specification and thus this revised definition should provide more flexibility to units burning these altnerative gaseous fuels.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 118

Comment: An ACC member company has a "Gas 2" stream that consists of the fuel produced by on-site ethylene production plants. The ethylene process off-gas is similar in composition to natural gas.

Comparison of Cobustion Propeties

This off-gas stream is a very clean fuel and the composition is as shown by the table below. The main difference is that this stream contains a significant amount of hydrogen which is a very clean fuel to use.

Column A represents a natural gas stream and Column B represents ethylene process off-gas from one of the member’s sites. This table further demonstrates that Gas 2 boilers should be subject to work practice standards like Gas 1 boilers because the fuel characteristics are similar or better.

Response: We appreciate the input from the commenter. EPA has modified the definition of gas 1 and adopted a fuel specification. See the preamble for detailed discussion of the fuel

specification. We are not finalizing limits for units firing natural gas, refinery gas, and other Gas 1 fuels. See preamble for rationale for selecting a work practice for these units.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 119

Comment: ACC also believes that EPA should clarify that boilers and process heaters burning hydrogen gas alone or with natural gas are Gas 1 boilers and subject only to work practice requirements. Hydrogen gas does not contain any HAP and burns cleaner than natural gas, so these units should be regulated as Gas 1 units and not be required to install costly controls and monitoring equipment.

Hydrogen is a common by-product gas of many chemical manufacturing processes and is routinely burned in boilers on-site in place of natural gas. For example, hydrogen is a by-product of the chlorine production process. The byproduct production of hydrogen gas from chlor-alkali production facilities is estimated at 389 thousand metric tons of hydrogen annually which is equivalent to the annual fuel consumption of 1.9 million light-duty hydrogen vehicles. The process itself involves the electrolysis of salt water which, in combination with other process steps, splits salt (NaCl) in solution into sodium hydroxide (NaOH), chlorine gas and hydrogen gas. In this process, hydrogen is a byproduct. In some facilities, approximately 10 percent of the hydrogen produced is used on site to produce hydrochloric acid (HCl), while larger portions are combusted on site to meet steam and power production needs. The chlorine chemistry industry has long employed cogeneration, an energy efficiency attained through the coproduction of electricity and process heat (also called combined heat and power or CHP) from a plant that is located at the chemical manufacturing facility. Significant efficiencies are gained from the productive use of the by-product heat, usually in the form of steam. While the efficiency gains can vary widely among individual sites, at its peak co-generation can be over 70 percent efficient.

Electrolytic hydrogen is very pure and it can be used for organic hydrogenation, catalytic reductions, to provide hot flames or protective atmospheres in welding technology, metallurgy or glass manufacture. Hydrogen should be considered a "clean fuel" – meaning it does not emit carbon dioxide, one of the greenhouses gases or other criteria pollutants. Recovering and burning the hydrogen also preserves existing reserves such as coal, oil and natural gas. Considering the vital and growing role of energy in global economic and environmental issues, the chlorine industry is likely to increase its use of co-generation. Because hydrogen is very pure and considered a clean fuel, EPA should classify the cogeneration use of hydrogen fuel as a Gas 1 fuel.

Response: We appreciate the input from the commenter. EPA has modified the definition of gas 1 and adopted a fuel specification. See the preamble for detailed discussion of the fuel

specification. We are not finalizing limits for units firing natural gas, refinery gas, and other Gas 1 fuels. See preamble for rationale for selecting a work practice for these units.

Commenter Name: Frederick W. Lash
Commenter Affiliation: Air Products and Chemicals, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-3178
Comment Excerpt Number: 1

Comment: Recognition of Pressure-Swing-Adsorption (PSA) Purge Gas as a Clean- Burning Fuel

If the agency retains the distinction between Gas 1 and Gas 2 facilities, defining the term "refinery gas" would prove helpful. Should the agency use the current refinery gas definition as found in the Refinery 1 NESHAP (Part 63 Subpart CC), or a similar version, Air Products wishes to ensure that "clean fuels" produced and/or used by independent entities not connected to a refinery's fuel gas system are recognized and considered by the agency in this ruling. An example of this is the steam methane reforming (SMR) commercial process Air Products and other industrial gas producers use to produce hydrogen, which refiners then utilize to satisfy EPA mandated sulfur reductions in gasoline and diesel fuel production.

In the SMR process, steam and a hydrocarbon feed (usually natural gas (NG) or refinery gas (RG)) are reacted at elevated temperatures over a catalyst in a process heater. The reaction forms a raw product stream comprised of hydrogen (H2), carbon monoxide (CO), and carbon dioxide (CO_2). The H2 is separated from this stream in a pressure-swing-adsorption (PSA) unit. The remaining gas, commonly called PSA purge gas, contains unrecovered H2 as well as the fuel species CO and methane along with up to 50 vol% inerts (mainly CO_2). This low-Btu gas is recycled back to the process heater as the predominant fuel with the remaining fuel balance comprised of NG or RG.

Part of the agency's concerns deal with combustion processes in boilers and process heaters, which promote the formation of carbon radicals that can lead to the generation of hazardous air pollutants (HAPs) as defined by the EPA. This occurs during fuel rich combustion and is readily evidenced by colored flames from the burners. However, when burning PSA purge gas in the SMR process, the flames are typically invisible. Flame shape and sizing are only detectable in the radiation patterns on the process heater walls. The lack of flame color is an indication of excellent combustion, where only the oxidation reaction of CO to CO_2 and H2 to H_2O is primarily occurring. The excellent combustibility (complete combustion) of PSA purge gas has been repeatedly confirmed through CO stack testing of the process heater flue gas, where CO levels are shown to be very minimal through testing via EPA Reference Method 10.

Recommendation: Since SMR PSA purge gas combusts very cleanly, the proposal is for the agency to specifically classify this gas (and others with similar combustion characteristics) as a clean-burning fuel and regulate it accordingly. Otherwise, Air Products estimates at least five of its SMR sources burning this fuel would be subjected to emission limitations, extensive monitoring and possible application of very expensive pollution controls under the proposed rule. It is also recommended that the term "refinery gas" be defined if the distinction between Gas 1 and Gas 2 Facilities remains in the rule.

Response: We appreciate the input from the commenter. EPA has modified the definition of gas 1 and adopted a fuel specification. See the preamble for detailed discussion of the fuel specification. We are not finalizing limits for units firing natural gas, refinery gas, and other Gas 1 fuels. See preamble for rationale for selecting a work practice for these units.

Commenter Name: Christopher Peters
Commenter Affiliation: Low Carbon Synthetic Fuels Association
Document Control Number: EPA-HQ-OAR-2002-0058-2942.1
Comment Excerpt Number: 2

Comment: The LCSFA believes that EPA did not consider the possibility that syngas could be used in boilers during its rule development process. This is clear because EPA has on numerous occasions recognized the environmental benefits of syngas. Indeed, in the companion rulemaking to the Boiler MACT defining secondary non-hazardous substances that are solid wastes, which informs the distinction between boilers subject to the Boiler MACT and those subject to CAA Section 129 standards for solid waste incineration units, EPA found that producing syngas by gasifying solid wastes would constitute “adequate processing” that could prevent a discarded material from being categorized as a solid waste.[footnote: See Identification of Non-Hazardous Secondary Materials That Are Solid Waste; Proposed Rule, 75 Fed. Reg. 31844, 31878 (June 4, 2010)] There, EPA acknowledged that syngas cleanup “at a minimum involves removal of sulfur and metals” and noted that syngas could be used in a combustion turbine, though it did not mention the possibility of using syngas in boilers.[footnote:Id.]

In addition to the proposed treatment of syngas in the rulemaking defining secondary non-hazardous substances that are solid waste, EPA previously promulgated an exclusion from the definition of solid waste for syngas fuel derived from hazardous waste as long as the syngas met specifications.[footnote: See 40 CFR §261.389(a)(3)] In the Subpart YYYY MACT rule for stationary combustion turbines, EPA similarly recognized the clean properties of syngas and included syngas within the definition of natural gas, noting that for the purposes of that rule, “the definition of natural gas includes similarly constituted fuels such as field gas, refinery gas, and syngas.”[footnote: See 40 CFR §63.6175] (emphasis added) Given that EPA has previously acknowledged the clean properties of syngas and that syngas, refinery gas, and natural gas are all similarly constituted, there is no rational basis for the proposal’s placement of natural gas and refinery gas in the Gas 1 subcategory while placing syngas in the more onerous Gas 2 subcategory.

Response: We appreciate the input from the commenter. EPA has modified the definition of gas 1 and adopted a fuel specification. See the preamble for detailed discussion of the fuel specification. We are not finalizing limits for units firing natural gas, refinery gas, and other Gas 1 fuels. See preamble for expansion of gas 1 definition and finalized work practice standards for all gaseous fuel boilers meeting the specifications for hydrogen sulfide and mercury. Based on the data in the record available for biogases most of these units fall below the specification and thus this revised definition should provide more flexibility to units burning these altnerative gaseous fuels.

Commenter Name: Bruce A. Steiner
Commenter Affiliation: American Coke and Coal Chemicals Institute
Document Control Number: EPA-HQ-OAR-2002-0058-2849.1
Comment Excerpt Number: 8

Comment: EPA has proposed the Gas 2 subcategory to encompass all gaseous fuels that are not natural gas or refinery gas. This catch-all subcategory includes landfill gas, coke oven gas, coal-derived gas, biogas, and other process gases. EPA offers no justification for combining these disparate gases into a single subcategory but it may have been driven by a lack of data. With just five sources in the Gas 2 subcategory with dioxin-furan data and just eight sources with data for Hg and HCl, EPA had tied its own hands by not collecting sufficient data to properly distinguish between fuels with significantly different chemical compositions, heating values, and combustion characteristics. EPA's decision to lump these Gas-2 sources together based on what they are not (e.g., because they are not burning natural or refinery gas) is arbitrary and unlawful. Gas 2 fuels are not interchangeable. These gaseous fuels are combusted at or near their point of generation and used to reduce reliance on fossil fuels. Therefore, a Gas 2 source cannot decide to burn landfill gas to help meet the Hg emission standards if they are not in the vicinity of a landfill. Similarly, coke oven gas is only available in the vicinity of coke batteries. Thus, most of the 199 Gas 2 sources cannot use coke oven gas to help meet the dioxin emission limits. Nor does it make environmental or economic sense to displace process gases with natural gas because flammable process gases must be combusted to meet health and safety requirements. Flaring process gases and burning natural gas to reduce emissions at the boiler increases facility-wide emissions, decreases energy independence, and wastes opportunities for energy efficiency. Process gas-fired sources are not candidates for fuel switching.
EPA must, as a result, evaluate and understand the emission characteristics of each process gas fuel to determine if its Gas 2 subcategory is properly defined as a reasonable aggregation of similar sources. EPA has proposed an arbitrary aggregation of dissimilar fuels in the Gas 2 subcategory, which would result in emission limits that are not achievable when burning some process gases even when implementing all available control measures. This should be a strong signal that further subcategorization is warranted prior to the promulgation of the final Boiler MACT rule. If EPA will be setting numeric emission limits for coke oven gas-fired boilers, then these units need a separate subcategory because they have no pathway to attain emission limits established by dissimilar landfill gas and biogas-fired units.

Response: See response to comment EPA-HQ-OAR-2002-0058-2998.1, excerpt 8 for coke oven gas-fired units subcategory.

Commenter Name: Kevin M. Dempsey
Commenter Affiliation: American Iron and Steel Institute
Document Control Number: EPA-HQ-OAR-2002-0058-2998.1
Comment Excerpt Number: 8

Comment: If EPA Decides to Impose Numerical Emission Limits for Gas 2 Fuels, EPA Should Develop a Separate Subcategory for Coke Oven Gas-Fired Units

EPA has proposed the Gas 2 subcategory to encompass all gaseous fuels that are not natural gas or refinery gas. This catch-all subcategory includes landfill gas, coke oven gas, coal-derived gas, biogas, and other process gases. EPA offers no justification for combining these disparate gases into a single subcategory but it may have been driven by a lack of data. With just five sources in the Gas 2 subcategory with dioxinfuran data and just eight sources with data for Hg and HCl, EPA had tied its own hands by not collecting sufficient data to properly distinguish between fuels with significantly different chemical compositions, heating values, and combustion characteristics. EPA's decision to lump these Gas 2 sources together based on what they are not (e.g., because they are not burning natural or refinery gas) is arbitrary and unlawful.

Gas 2 fuels are not interchangeable. These gaseous fuels are combusted at or near their point of generation and used to reduce reliance on fossil fuels. Therefore, a Gas 2 source cannot decide to burn landfill gas to help meet the Hg emission standards if they are not in the vicinity of a landfill. Similarly, coke oven gas is only available in the vicinity of coke batteries. Thus, most of the 199 Gas 2 sources cannot use coke oven gas to help meet the dioxin emission limits. Nor does it make environmental or economic sense to displace process gases with natural gas because flammable process gases must be combusted to meet health and safety requirements. Flaring process gases and burning natural gas to reduce emissions at the boiler increases facility-wide emissions, decreases energy independence, and wastes opportunities for energy efficiency. Process gas-fired sources are not candidates for fuel switching.

EPA must, as a result, evaluate and understand the emission characteristics of each process gas fuel to determine if its Gas 2 subcategory is properly defined as a reasonable aggregation of similar sources. EPA has proposed an arbitrary aggregation of dissimilar fuels in the Gas 2 subcategory, which would result in emission limits that are not achievable when burning some process gases even when implementing all available control measures. This should be a strong signal that further subcategorization is warranted prior to the promulgation of the final Boiler MACT rule. If EPA will be setting numeric emission limits for coke oven gas-fired boilers, then these units need a separate subcategory because they have no pathway to attain emission limits established by dissimilar landfill gas and biogas-fired units.

EPA's current database is insufficient to understand emissions from coke oven gas-fired sources. Of the three units identified in the EPA database as coke oven gas-fired, two have been confirmed as burning petroleum coke, a solid fuel, and not coke oven gas. These data must be excluded from any gaseous fuel analysis. The only remaining emissions data in the EPA dataset for coke oven gas-fired units comes from a source test snapshot of a recovery coke plant in West Virginia that uses a desulfurization system. This limited data from a single source cannot adequately represent the variability inherent in the coke oven gas-fired sources identified by EPA within the Gas 2 subcategory. However, the data can, and do, indicate significant differences between coke oven gas emissions and other Gas 2 process gases. [For a discussion of these differences, we direct you to the comments of the American Petroleum Institute and the National Petrochemical Refiners Association, which reveal significant differences in the emission characteristics among the Gas 2 fuels.]

Response: Based on the revised gas 1 specification definition and data available in the record, EPA expects most of the units that exceed the specification will be firing coke oven gas. Therefore the remaining units in the gas 2 subcategory are more homogeneous than the units included in the proposed gas 2 MACT floor analysis.

See response to comment EPA-HQ-OAR-2002-0048-2632.1, excerpt 19 for inadequacies of the Gas 2 dataset.

Commenter Name: Bruce A. Steiner
Commenter Affiliation: American Coke and Coal Chemicals Institute
Document Control Number: EPA-HQ-OAR-2002-0058-2849.1
Comment Excerpt Number: 10

Comment: To gain a better understanding of the potential risk faced by coke oven gas-fired units under the broad Gas 2 subcategory proposed by EPA, an ACCCI member company conducted stack tests on four coke oven gas-fired boilers in July 2010. The test results confirm that the proposed Gas 2 emission limits for HCl, Hg, and CO are not achievable for these coke oven gas-fired boilers using commercially available emission control technologies. The tests were performed on four identical tangentially-fired industrial boilers. Each boiler has a rated heat input capacity of 650 MMBTU/hour and fires only gaseous fuels, comprised of a mixture of coke oven gas and blast furnace gas with supplementary natural gas, that are supplied to the boilers from common headers for each fuel. Typical fuel gas analyses are provided in (see submittal for Table 1). The boilers operated at 73% to 87% (average 83%) of design heat input capacity during the tests. The average contribution of each fuel to total heat input during the tests was 50% coke oven gas, 39% blast furnace gas and 11% natural gas (see submittal for Table 2).

The test program included the following measurements in each boiler stack:
* Group A:
o CO by EPA Method 10;
o Dioxins and furans by EPA Method 23;
o HCl and filterable non-sulfuric acid PM by EPA Method 26A, combined with EPA Method 5B;
* Group B:
o Mercury and filterable non-sulfuric acid PM by EPA Methods 29 and 101A, combined with EPA Method 5B (modified);
* Stack gas flow rate by EPA Method 2 (all tests); and
* Oxygen, carbon dioxide and moisture concentration by EPA Methods 3A and 4 (all tests).

Three 4-hour test runs were performed on each of the four boilers. Group A and Group B tests were not conducted simultaneously. Tests were performed at approximately the same time of day and under comparable operating conditions. The test methods for CO, Hg, HCl and dioxins/furans are among those specified by EPA for tests conducted under the ICR for this rule and in Table 5 to Subpart DDDDD of Part 63– Performance Testing Requirements of the proposed rule.

Method 5B was selected for filterable PM because it is believed to be a superior surrogate for non-mercury metallic HAPs when sulfuric acid may be present, as discussed elsewhere in these comments. Sulfur dioxide (SO2) concentrations in the exhaust gas indicate that sulfuric acid may be present at concentrations on the order of 5- 7 ppmv, which represents a potentially large fraction of the proposed filterable PM limit (on a lb/MMBTU basis). Method 5B is designed to mitigate the effect of sulfuric acid on the filterable PM results, which allows for a more accurate surrogate for non-mercury metallic HAP. For the Method 29 and Method 101A tests, filterable PM samples were collected with the probe and filter temperature at 160°C as specified in Method 5B, but the laboratory analysis was modified by drying the samples in a desiccator at room temperature as specified in Methods 29 and 101A rather than in an oven at 160°C as specified in Method 5B, so that Hg was preserved in these samples. For the Method 26A tests, Method 5B was performed normally.

The test results show highly variable CO emissions with an average concentration 28 times higher than the proposed limit. Also, HCl and Hg values exceed the proposed limits by more than an order of magnitude (see submittal for Table 3 and Figure 1) rendering them unachievable. Highly variable CO results among the four identical units were not unexpected due to the presence of blast furnace gas in the fuel mix,4 the nature of these low BTU fuels, and normal variations in boiler operations even at a relatively constant total heat input near design capacity. These short duration tests cannot capture the full range of normal operating conditions that might be experienced over several years. However, they are important indications that coke oven gas-fired units are significantly different from other Gas 2 units and that further data and analysis are needed before setting numeric emission limits for coke oven gas-fired units.

The levels of HCl, Hg, and CO exceed the proposed Gas 2 limits by such a large margin that available emission control measures would be insufficient to achieve the proposed Gas 2 limits. If optimistic assumptions for control efficiency are applied to the uncontrolled levels measured in these tests, it is clear that the Gas 2 emission limits cannot be reliably achieved (see submittal for Table 4). Even assuming 99% HCl removal, the proposed Gas 2 limits could not be achieved. This control efficiency is very optimistic given the

[Footnote 3: The test method for dioxins/furans was left blank in Table 5 of the proposed rule. EPA should correct this oversight in the final rule. We assume that Method 23 is the intended method for these compounds based on the preamble discussion at 75 Fed. Reg. 32013.]

[Footnote 4: Blast Furnace Gas contains large amounts of carbon monoxide and no organic HAP, thus the presence of CO in the exhaust gas from BFG fuel mixtures may not be an indication of the presence of organic HAP. The highest CO was observed during tests on Boiler 12, which is attributed to the higher relative contribution of blast furnace gas at that boiler.]

Response: See response to comment EPA-HQ-OAR-2002-0058-2998.1, excerpt 8 for coke oven gas-fired units subcategory.

Commenter Name: Mark W. Kowlzan
Commenter Affiliation: Packaging Corp. of America
Document Control Number: EPA-HQ-OAR-2002-0058-2913.1
Comment Excerpt Number: 11

Comment: In the past six years, PCA invested over $24 miJIion (unsubsidized) to build anaerobic reactors and biogas collection, conditioning and combustion systems to develop renewable energy sources at two of our pulp and paper operating locations. As mentioned earlier, two of our company boilers are classified as "Other Gas" boilers. In both cases, the boilers in question combust biogas collected from facility anaerobic wastewater treatment reactors, Biogenic gas and natural gas, as fired, are essentially one in the same aside from the fact that biogenic gas contains a dead load of carbon dioxide. Under the proposed rule, both of our biogas-fired boilers are subject to the "Other Gas" subcategory emission limits. We estimate that our compliance cost for these two units will exceed $30 million in capital and an additional $2 million per year in operating costs. The estimated compliance cost of the proposed rule exceeds the capital cost of constructing these renewable energy projects by 50 percent. The proposed rule effectively penalizes innovative renewable energy investment and discourages any consideration for further implementation or expansion of those kinds of projects.
Biogas fuel produced from anaerobic wastewater treatment plants should be classified in the natural/refinerygas subcategory.

Response: We appreciate the input from the commenter. EPA has modified the definition of gas 1 and adopted a fuel specification. See the preamble for detailed discussion of the fuel specification. We are not finalizing limits for units firing natural gas, refinery gas, and other Gas 1 fuels. See preamble for expansion of gas 1 definition and finalized work practice standards for all gaseous fuel boilers meeting the specifications for hydrogen sulfide and mercury. Based on the data in the record available for biogases most of these units fall below the specification and thus this revised definition should provide more flexibility to units burning these altnerative gaseous fuels.

Commenter Name: Douglas A. McWilliams
Commenter Affiliation: ArcelorMittal USA, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2811.1
Comment Excerpt Number: 14

Comment: The proposed "Gas-2" subcategory would encompass all gaseous fuels that are not natural gas or refinery gas. This catch-all subcategory includes landfill gas, coke oven gas, coal-derived gas, biogas, and unidentified "other" process gases. While EPA offers no justification for combining these disparate gases into a single subcategory, it may have been driven by a lack of data. With just five sources in the Gas-2 subcategory with dioxin-furan data and just eight sources with data for mercury and HC1, EPA tied its own hands by failing to collect sufficient data to distinguish between fuels with significantly different chemical compositions, heating

values and combustion characteristics. EPA's decision to lump these Gas-2 sources together based on what they are not (i.e., not natural or refinery gas) is arbitrary and unlawful.
Gas-2 fuels are not interchangeable. Gas-2 fuels are combusted at or near where they are generated and used to reduce reliance on fossil fuels. Therefore, a boiler burning coke oven gas cannot choose to burn landfill gas to achieve the mercury emission standards set by landfill gas-fired boilers if they are not in the vicinity of a landfill. Similarly, coke oven gas is only available to boilers and process heaters operating in the vicinity of coke batteries and most of the 199 Gas-2 sources cannot choose to burn COG to help meet dioxin emission limits. Nor does it make environmental or economic sense to displace Gas-2 process gases with natural gas, as discussed above, because flammable process gases must be combusted to meet health and safety requirements. Flaring process gases and burning natural gas to reduce emissions at the boiler increases facility-wide emissions, decreases energy independence, and wastes opportunities for energy efficiency. Gas-2 sources are not similar units that can adjust their fuels to those used to establish the MACT floor emission limit for the subcategory.
EPA must evaluate and understand the emission characteristics of each process gas fuel to determine if the Gas-2 subcategory is properly defined as a reasonable aggregation of similar sources. The current proposal to arbitrarily aggregate dissimilar fuels in the Gas-2 subcategory would result in emission limits that are not achievable when burning coke oven gas - even when implementing all available control measures. This is a powerful signal that further subcategorization is necessary prior to the promulgation of the final Boiler MACT rule. If EPA decides to set numeric emission limits for coke oven gas-fired boilers, then these units need a separate subcategory because they have no pathway to attain emission limits established by dissimilar landfill gas and biogas-fired units.
EPA's current database is insufficient to understand emissions from coke oven gas-fired sources. Of the three units identified in the ICR database as COG-fired, two have been confirmed as burning petroleum coke, a solid fuel, and not coke oven gas. These data must be excluded from any gaseous fuel analysis. The only remaining emissions data in the EPA dataset for COG-fired units comes from a source test snapshot of a byproducts recovery coke plant in West Virginia that uses a desulfurization system. This limited data from a single source cannot adequately represent the variability inherent in the COG-fired sources identified by EPA within the Gas-2 subcategory. However, the data can, and do, indicate significant differences between COG emissions and other Gas-2 process gases. [Footnote: For a discussion of these differences, we direct you to the comments of the American Petroleum Institute and the National Petrochemical Refiners Association, which reveal significant differences in the emission characteristics among the Gas-2 fuels.]

Response: See response to comment EPA-HQ-OAR-2002-0048-2632.1, excerpt 19 for inadequacies of the Gas 2 dataset.
See response to comment EPA-HQ-OAR-2002-0058-2998.1, excerpt 8 for coke oven gas-fired units subcategory.

Commenter Name: Douglas A. McWilliams
Commenter Affiliation: ArcelorMittal USA, Inc

Document Control Number: EPA-HQ-OAR-2002-0058-2811.1
Comment Excerpt Number: 16

Comment: Based on this analysis, it is technically infeasible for coke oven gas-fired boilers to achieve the proposed Gas-2 emission limits. Therefore, if EPA imposes numerical emission limits on coke oven gas-fired units despite our prior objections, the Agency must develop a separate subcategory for coke oven gas-fired units which has limits that are achievable based on the unique chemical composition and emission profile of that process gas.

Response: See response to comment EPA-HQ-OAR-2002-0058-2998.1, excerpt 8 for coke oven gas-fired units subcategory.

Commenter Name: Chris Korleski
Commenter Affiliation: Ohio EPA
Document Control Number: EPA-HQ-OAR-2002-0058-2818.1
Comment Excerpt Number: 30

Comment: The US EPA should also consider separately or clearly define the treatment of gaseous fuels derived from biomass. Such fuels generated by bio-digester systems, wastewater treatment plants, and landfills are currently fired in boilers and likely to grow in future use. Depending on the source, the fuel is likely to contain chlorine or mercury and likely to have constituents that can lead to the formation of dioxins and furans.

Response: We appreciate the input from the commenter. EPA has modified the definition of gas 1 and adopted a fuel specification. See the preamble for detailed discussion of the fuel specification. We are not finalizing limits for units firing natural gas, refinery gas, and other Gas 1 fuels. See preamble for expansion of gas 1 definition and finalized work practice standards for all gaseous fuel boilers meeting the specifications for hydrogen sulfide and mercury. Based on the data in the record available for biogases most of these units fall below the specification and thus this revised definition should provide more flexibility to units burning these altnerative gaseous fuels.

Commenter Name: Kevin M. Dempsey
Commenter Affiliation: American Iron and Steel Institute
Document Control Number: EPA-HQ-OAR-2002-0058-2998.1
Comment Excerpt Number: 32

Comment: We also note that there is very little difference between the emissions from the top performing sources in the Gas 2 subcategory as compared with the Gas 1 subcategory. As a result, in the alternative to further subcategorization of Gas 2 units as described below for coke oven gas-fired units, EPA would be justified in concluding that the Gas 1 and Gas 2 subcategories should be combined into a single gas-fired subcategory, which would be regulated by work practice standards for the reasons EPA explains in the preamble. At a minimum, units fired with process gases generated in chemical plants, pulp and paper plants, iron and steel plants, and similar operations should be included in the Gas 1 subcategory because the emissions data show very little difference in performance between units at these facilities and Gas 1 units.

Response: We appreciate the input from the commenter. EPA has modified the definition of gas 1 and adopted a fuel specification. See the preamble for detailed discussion of the fuel specification. We are not finalizing limits for units firing natural gas, refinery gas, and other Gas 1 fuels. See preamble for rationale for selecting a work practice for these units.

Subcategories: Biomass: Dutch Oven/Susp Burner

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 151

Comment: Dutch ovens and suspension burners are fundamentally different in design and fuel firing capabilities. Dutch ovens have two chambers. Solid fuel is dropped down into a refractory lined chamber where drying and gasification take place in the fuel pile. Gases pass over a wall into the second chamber where combustion is completed. Dutch ovens are capable of burning high moisture fuels such as bark, but have low thermal efficiency and are unable to respond rapidly to changes in steam demand. Suspension burners combust fine, dry fuels such as sawdust and sanderdust in suspension. Rapid changes in combustion rate are possible with this firing method. They can be of watertube or firetube design, and may be package units or field-erected. It is not appropriate to combine these two types of boilers given their much different characteristics, and a subcategory should be established for each.
In the Phase I survey database for major sources with boilers, a “True” in the Dutch oven column appears for 24 boilers. However, 13 of the installation dates are more recent than 1960, making it unlikely these are really of the Dutch oven design. Regarding suspension burners, it is very difficult to use the survey database to identify true suspension burners. Many biomass boilers indicating fuels are burned in suspension are actually stokers or fluidized beds where a small portion of the fuel may be fed to the boiler and burned in suspension. We suspect there are fewer than 30 of units that burn all of the biomass fuel in suspension. They would mainly be located at particleboard, hardboard, and medium density fiberboard plants that have fine dry fuels available.
The ERG April 26, 2010 MACT floor memo shows 17 units with CO tests in the Dutch oven/suspension burner biomass subcategory. Only two of these appear to be true Dutch ovens:
* WAGraysHarborPaper No. 6 Boiler
* ORRosboroSpringfield DV 01.1
The following appear to be suspension burners:
* TXDibollTemple-Inland PB-44
* ORFlakeboardEugene Boiler-2

* OHSauderWoodArchbold B008, B009
* MNNorbordMinnesota Konus No. 1 and 2 (process heaters).

Response: EPA has revised the definitions and separated this category into hybrid suspension grate boilers and process heaters, which fire high moisture fuel, predominantly bagasse. The remainder of the units in the dutch oven and suspension burner subcategory are firing blended biomass with similar CO emissions and PM emisisons and none of the remaining suspension burners had THC data available. EPA based the subcategorization on the reported classifications of each boiler in addition to any corrections received during the public comment period.

Commenter Name: David A. Buff
Commenter Affiliation: Golder Associates Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2801.1
Comment Excerpt Number: 8

Comment: However, EPA has inappropriately subcategorized suspension burners/dutch ovens designed to burn biomass as a single subcategory. Dutch ovens are much different in design and operation than suspension burners, and should be in a separate subcategory. Also, there are suspension burners that burn all their fuel in suspension and have no grate. These boilers burn dry fuel that can be combusted totally in suspension. Emissions of organic HAPs and PM from these type boilers are much different than boilers that must utilize a combination of suspension firing and grate firing in order to properly and totally combust a wet fuel. Therefore, EPA should set separate subcategories for organic HAPs (or CO) and for metal HAPs and PM for:

* Bagasse boilers (48 to 55 percent moisture)

* Suspension burners designed to burn dry biomass (<30 percent moisture),

* Suspension burners designed to burn wet biomass (>30 percent moisture)

* Dutch ovens

The bagasse the FSl burns in its boilers always has between 48 percent and 55 percent moisture. This high level of moisture is dictated by the sugar cane grinding and washing process. The boilers are designed as hybrid suspension/grate-floor burners in which the wet fuel first undergoes drying and then combustion in suspension within the furnace, with any remaining unburned fuel falling onto the grate to complete combustion.

However, boilers burning dry biomass (i.e., <20 to 30 percent moisture fuel) do not need to undergo this initial drying process, since the fuel is already dry enough to combust when it enters the boiler. Excess air levels can be decreased and combustion efficiency improves. Thus, suspension burners burning dry biomass can be and are designed differently, and are operated differently, than suspension/floor-grate burners burning wet biomass.

Response: See preamble for a new hybrid suspension/grate burner category and response to comment EPA-HQ-OAR-2002-0058-3213.1, excerpt 151 for the modifications made to the dutch oven/suspension burner subcategory.

Subcategories: Biomass: Stoker/Sloped Grate

Commenter Name: Michael L. Steele
Commenter Affiliation: CraftMaster Manufacturing, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-1907.1
Comment Excerpt Number: 3

Comment: An example of a questionable categorization is CraftMasters No3Boilerthatfiresbiomass through a combination of Air-swept Stokers (14% of heat input in 2009), Suspension Burners (70%), and natural gas (16%). Suspension Burners used by CraftMaster are similar to pulverized coal burners.

Per the "Inventory of Major Source Boilers and Process Heaterstl database, USEPA has placed the N03 Boiler in the "Stoker/Sloped Gate/Other" combustor design category. It is assumed this is the same as the "Stoker" subcategory. It is clear that the No3 Boiler does not have mechanical stokers and the air-swept stokers (defined as Suspension Boiler in proposed regulations) provided only 14% of the heat input in 2009. The primary firing method is the suspension burners with 700/0 of the heat input. Then the primary firing method used is apparently not considered by USEPA in establishing what subcategory a unit is in.

To summarize, USEPA appears to have an excessive number of subcategories for biomass-fired units without proper definition. Many units could be classified in the incorrect subcategory including those in the MACT Floor. It is suggested that these issues be investigated with intent of possibly reducing the number of biomass subcategories. This would alleviate the confusion associated with the lack of definitions, etc. Also, the number of units included in the MACT Floor would be increased and associated issues would be reduced as well.

Response: See the final rule for revised definitions of each combustor design. EPA established a hierarchy for assinging each combustor designs as described in the memorandum "Revised Development of Baseline Emission Factors for Boilers and Process Heaters at Commercial, Industrial, and Institutional Facilities". It did not determine the heat input provided through each separate combustor design due to limited data provided in the survey with respect to the heat input channelled through separate combustor designs.

Subcategories: Biomass: Fluidized Bed

Commenter Name: Michael L. Steele
Commenter Affiliation: CraftMaster Manufacturing, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-1907.1
Comment Excerpt Number: 27

Comment: Combustor-based Limits

Wouldn't combustor design have an impact on HCl emissions if a Fluid bed was using limestone media? Are there any units like this in the HCl MACT Floors? If so, they should be evaluated as a possible subcategory.

Response: EPA determined that HCl emissions are more influenced by fuel type instead of combustor design. For the solid fuel units that are the floor there are various combustor design types including fluidized beds.

Commenter Name: G. Vinson Hellwig and Robert H. Colby
Commenter Affiliation: National Assocation of Clean Air Agencies
Document Control Number: EPA-HQ-OAR-2002-0058-2841.1
Comment Excerpt Number: 28

Comment: NACAA agrees that fluidized bed combustion units (either biomass or coal-fired) are of sufficiently different design and anticipated performance that a separate subcategory may be warranted, but does not see a justification for the other subcategories proposed by EPA for the Boiler MACT rule.

Response: EPA agrees with the commenter about separate subcategory for fluidized beds. However, EPA also maintains that the other subcategories are appropriate for organic HAP in addition to new categories for non-continental, hybrid suspension-grate burners, and limited use units. See the final rule for discussion of new categories.

Subcategories: Biomass: Fuel Cell

Commenter Name: Arthur N. Marin
Commenter Affiliation: NESCAUM
Document Control Number: EPA-HQ-OAR-2002-0058-2893.1
Comment Excerpt Number: 17

Comment: NESCAUM also recommends eliminating the proposed "fuel cell" subcategory for wood-fired boilers in the MACT rule. A fuel cell is generally understood to create electricity directly from a fuel gas without combustion.1 As such, a true fuel cell would not be subject to the ICI boiler rule. One does not find in the technical literature a discussion of “fuel cell” combustion units. The units in EPA’s database that it styles as “fuel cell” units appear to be newer than most, and for that reason, relatively fuel efficient and low-emitting, but there does not appear to be any difference in fundamental design that would warrant establishment of a separate category.

Response: See response to comment EPA-HQ-OAR-2002-0058-2841.1, excerpt 26.

Commenter Name: G. Vinson Hellwig and Robert H. Colby
Commenter Affiliation: National Assocation of Clean Air Agencies
Document Control Number: EPA-HQ-OAR-2002-0058-2841.1
Comment Excerpt Number: 26

Comment: The “fuel cell” subcategory of wood-fired boilers is especially problematic. A fuel cell is generally understood to create electricity directly from a fuel gas without combustion.[58 See, e.g., Standard Handbook of Powerplant Engineering, Section 8.6, Elliot (ed), McGraw Hill, 1998.] As such, a true fuel cell would not be subject to the ICI Boiler Rule. One does not find in the technical literature a discussion of “fuel cell” combustion units. A visit to the website of one of the manufacturers of a unit (Wellon, Inc) that EPA asserts is a wood-fired fuel cell combustion unit reveals that the company does refer to certain of its units as fuel cells, but this reference is to a marketing approach to the sale of modular units, rather than a particular design.[The company will sell a fuel cell that is either top-fired or bottom-fired.] The units in EPA’s database that it styles as “fuel cell” units appear to be newer than most, and for that reason, relatively fuel efficient and low emitting, but there does not appear to be any difference in fundamental design that would warrant establishment of a separate category.

Creating larger numbers of subcategories usually leads to higher MACT floors in two ways. First, if a small number of the best performers (e.g., fuel cells) can be culled from a larger group into their own subcategory, the MACT floor for the larger group (the wood-fired boilers) will rise. Second, because the small group will have a small number of tests, the statistical variability of the small group will also increase, leading to MACT floor increases for both the larger group and the smaller group.[EPA’s proposed MACT standards for wood-fired boilers are identical for all pollutants except CO.]

Response: EPA disagrees with removing the fuel cell subcategory. This combustor type was a unique option that could be selected in the ICR survey. The ICR survey received a separate public comment period and the fuel cell category was not disputed during the time of the survey.

Subcategories: Coal: Fluidized Bed

Commenter Name: Robin Mills Ridgway
Commenter Affiliation: Purdue University
Document Control Number: EPA-HQ-OAR-2002-0058-2782.1
Comment Excerpt Number: 2

Comment: Due to the nature of CFB technology, the ability to combustion optimize (or "tune") the boiler to minimize CO emissions is extremely limited in comparison to pulverized and stoker firing technologies. In CFB combustion technology there is a directly inverse relationship between CO emissions and NOx emissions. As the furnace temperature is raised to enhance carbon burn out and decrease CO emissions, NOx emissions increase. NOx emissions in a CFB boiler are inherently low due to the low temperature combustion in the furnace.

CO emissions increase and become less consistent at higher loads for a stoker fired boiler whereas CO emissions increase at lower loads for the CFB fired boiler. This difference in performance has to do with many factors that are unique to the combustion technology and unit design. The increase in CO emissions at lower loads for the CFB has to do with thermal stratification in the furnace whereas the increase in CO for a stoker fired or pulverized coal boiler has to do with combustion residence time.

[See submittal for graph showing Boiler 5 CO & NOx emissions versus bed temperature.]

[See submittal for graph showing Boiler 5 CO emissions versus load.]

Response: See the preamble for a discussion of how CO limits were modified.

Commenter Name: G. Vinson Hellwig and Robert H. Colby
Commenter Affiliation: National Assocation of Clean Air Agencies
Document Control Number: EPA-HQ-OAR-2002-0058-2841.1
Comment Excerpt Number: 27

Comment: NACAA agrees that fluidized bed combustion units (either biomass or coal-fired) are of sufficiently different design and anticipated performance that a separate subcategory may be warranted, but does not see a justification for the other subcategories proposed by EPA for the Boiler MACT rule.

Response: EPA agrees with the commenter on maintaining a separate subcategory for fluidized bed boilers but disagrees that other combustor designs are not relevant.

Subcategories: Combination Fuel Units

Commenter Name: Caroline Dauzat
Commenter Affiliation: Rex Lumber
Document Control Number: EPA-HQ-OAR-2002-0058-1845
Comment Excerpt Number: 3

Comment: Biomass boilers should be evaluated on their own rather than being lumped in with boilers burning a combination of fuels.

Response: Please refer to the preamble for discussion of combination fuel units.

Commenter Name: Charles McRae
Commenter Affiliation: Rex Lumber
Document Control Number: EPA-HQ-OAR-2002-0058-1846
Comment Excerpt Number: 10

Comment: Limits for biomass boilers should be based on data from units burning only biomass, not combinations of other fuels.

Response: Please refer to the preamble for discussion of combination fuel units.

Commenter Name: Los Angeles Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1778
Comment Excerpt Number: 19

Comment: Do not penalize or discourage the use of clean, renewable fuels like biomass. Coal-fired boilers using coal and biomass are classified as coal boilers even though they may utilize 90 percent biomass.

Response: Please refer to the preamble for discussion of combination fuel units.

Commenter Name: Los Angeles Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1778
Comment Excerpt Number: 50

Comment: EPA should set more reasonable limits that reflect the variability of real-world, best performing boilers. We believe the proposed Boiler MACT CO limit for boilers burning biomass in conjunction with coal will not be achievable as a practical matter.

International Paper has seven boilers that burn biomass in coal amounts at the rate of 10 percent. They classify them as coal boilers under the proposal that would be subjected to unachievable CO limits. The CO limits for these combination boilers should be the same as the ones for the biomass boilers.

Response: Please refer to the preamble for discussion of combination fuel units.

Commenter Name: Houston Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1876
Comment Excerpt Number: 65

Comment: Combination boilers, those burning multiple fuels, can be addressed through subcategories.

Response: Please refer to the preamble for discussion of combination fuel units.

Commenter Name: Houston Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1876
Comment Excerpt Number: 95

Comment: EPA should set more reasonable limits that reflect the variability of real-world best performing boilers. We believe the proposed Boiler MACT CO limit for boilers burning biomass in conjunction with coal will not be achievable as a practical matter. International Paper has seven boilers that burn biomass with coal in amounts greater than 10 percent that classifies them as "coal" boilers under the proposal that would be subjected to unachievable CO limits. The CO limits for these combination boilers should be the same as the ones for biomass-fired boilers. If we continue to encourage and expand use of renewable, carbon neutral biomass in this country, the rule needs to change dramatically.

Response: Please refer to the preamble for discussion of combination fuel units.

Commenter Name: Houston Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1876
Comment Excerpt Number: 116

Comment: When the court vacated the earlier ICI Boiler MACT rule and state and local permit authorities were faced with developing case-by-case MACT permits, NACAA collected existing test data from over 40 state and local permitting agencies, including hundreds of data points that NACAA used to calculate MACT floors, which were substantially lower than those adopted by EPA in its earlier rule. The NACAA database was provided to EPA in June of 2009.
Many units combust mixtures of fuels.
When switching fuels, emissions of one HAP may increase while those of another HAP may decrease without clear correlation. In its model permit guidance, NACAA considered only those results where a source was burning 100 percent of one category of fuel during the test.
Under NACAA's recommended approach, sources would be separately tested for compliance with each applicable limit. NACAA also noted that during compliance testing, sources may be able to establish unit-specific correlations for operation of different fuels.
EPA apparently did not use any of the testing in the NACAA database to establish the MACT floors. The EPA data includes numerous entries where a source was combusting different fuels, which NACAA believes will be difficult to translate into enforceable MACT limitations.

Response: Please refer to the preamble for discussion of combination fuel units.

Commenter Name: Houston Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1876
Comment Excerpt Number: 137

Comment: EPA needs to provide alternative organic HAP limits for units that co-fire coal and biomass. These units are being penalized under the proposed subcategories. Our units that fire more than 10 percent coal and biomass are placed in a coal subcategory, but will have trouble meeting the organic HAP limits. As a compliance strategy, units may have to switch away from biomass and burn more coal. This unintended consequence of replacing biomass and fossil fuel is contrary to national policy and encourages the use of more renewable biomass fuel.

Response: Please refer to the preamble for discussion of combination fuel units.

Commenter Name: Houston Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1876
Comment Excerpt Number: 118

Comment: EPA's approach is to categorize sources according to fuels that they are "designed to combust," and allow sources to comply with what EPA apparently considers the "least stringent" standard for any of the fuels that it may combust. NACAA believes that this approach is likely to be unworkable for many sources and may not be legal.

Response: Please refer to the preamble for discussion of combination fuel units.

Commenter Name: Carl Johnson
Commenter Affiliation: Southern Pressure Treaters' Association
Document Control Number: EPA-HQ-OAR-2002-0058-1867.1
Comment Excerpt Number: 3

Comment: The limits set for biomass boilers should be based on data from units burning only biomass instead of on boilers burning a combination of other fuels.
The limits that EPA set for biomass fuel hazardous air pollutants were evidently based on which facility happened to be burning biomass with the lowest levels of these materials. The limits should have been based on control technology.

Response: Please refer to the preamble for discussion of combination fuel units.

Commenter Name: Arlington Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1779

Comment Excerpt Number: 10

Comment: Finally, over 60 boilers burned biomass with as little as 10 percent coal, but the proposal classifies them as coal boilers, setting unachievable CO limits. The CO limits of these combination boilers should be the same as the ones for biomass fired boilers. If we want to continue to encourage and expand the use of renewable carbon neutral biomass, the rule needs to change dramatically.

Response: Please refer to the preamble for discussion of combination fuel units.

Commenter Name: Michael L. Steele
Commenter Affiliation: CraftMaster Manufacturing, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-1907.1
Comment Excerpt Number: 12

Comment: The proposed rules specify that a unit fired on just over 10% biomass and just under 900/0 natural gas, is considered a biomass unit. Is the same criteria used for units in the biomass MACT Floors? If so, such a unit should not be in the biomass MACT Floor. The Floor for biomass should be based on all-biomass fired or substantially so. If not, how can an aH-biomass fired unit comply with a MACT limit derived from data that includes essentially gas-fired units?

Response: See the preamble for response to the pollutant-by-pollutant approach and achievability of standards as well as response to how the subcategories and thresholds were adjusted in the final rule to better accommodate combination fuel boilers.

Commenter Name: Michael L. Steele
Commenter Affiliation: CraftMaster Manufacturing, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-1907.1
Comment Excerpt Number: 21

Comment: How are multiple fuels handled when one fuel is in one subcategory (say biomass) and another is in another subcategory (say natural gas)? How is test data affected? F factor for combined fuels or just fuel associated with subcategory we’re testing compliance for? What other implications are there in the proposed rules?

Response: The preamble final rule outlines the annual heat input thresholds that define what subcategory a unit belongs to. To determine compliance with the emission limits, you must use the F-Factor methodology and equations in sections 12.2 and 12.3 of EPA Method 19 at 40 CFR part 60.

Commenter Name: Arlington Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1779
Comment Excerpt Number: 41

Comment: When the court vacated the earlier ICI Boiler MACT rule and state and local permit authorities were faced with developing case-by-case MACT permits, NACAA collected existing test data from state and local permitting agencies. Over 40 agencies provided hundreds of data points that NACAA used to calculate MACT floors, which were substantially lower than those adopted by EPA in its earlier rule. The NACAA database was provided to EPA in June of 2009.

Many units combust mixtures of fuels. No clear correlation has been established to evaluate the emissions performance of different units combusting different mixtures of fuels –-and indeed, when switching fuels, emissions of one HAP may increase while those of another HAP may decrease. In its model permit guidance NACAA considered only those results where a source was burning 100 percent of one category of fuel during the test. Under NACAA’s recommended approach, sources would be separately tested for compliance with each applicable limit. NACAA also noted that during compliance testing, sources may be able to establish unit-specific correlations for operation of different fuels.

EPA apparently did not use the testing in the NACAA database to establish the MACT floors. The EPA data includes numerous entries where a source was combusting different fuel mixes, which NACAA believes will be difficult to translate into enforceable MACT limitations.

EPA’s approach is to categorize source categories according to fuels that they are designed to combust and allow sources to comply with what EPA apparently considers the least stringent standard for any of the fuels that it may combust. NACAA believes that this approach is likely to be unworkable for many sources.

Response: Please refer to the preamble for discussion of combination fuel units.

Commenter Name: Richard Holland
Commenter Affiliation: Packaging Corporation of America
Document Control Number: EPA-HQ-OAR-2002-0058-2385
Comment Excerpt Number: 2

Comment: We recommend that the Agency rework the source subcategories to include boilers that combust a combination of solid fuels and establish emission limits reflective of the variation in fuels and fuel quality.

Response: Please refer to the preamble for discussion of combination fuel units.

Commenter Name: Don Grimm
Commenter Affiliation: Hood Industries, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2352
Comment Excerpt Number: 3

Comment: EPA must adjust the proposed subcategories to properly accommodate the unique characteristics of combination boilers.
Within certain industry sectors, boilers are commonly used that co-fire coal in an amount greater than 10% heat input basis with at least 10% biomass. These "combination boilers" that simultaneously burn coal and biomass have different emission profiles than units that burn coal or units that burn biomass. As a result, combination boilers do not fit cleanly into either the coal-fired boiler subcategory or the biomass-fired boiler subcategory. To better accommodate the actual performance of combination boilers, we recommend that EPA adjust the proposed subcategory for combination boilers so that they belong to the coal subcategory for purposes of regulating the fuel-based HAP (i.e., metals/PM, HAP acid gases, and mercury) and the biomass subcategory for purposes of regulating the combustion-based HAP (i.e., CO (as a surrogate for organic HAPs) and dioxins/furans).

As the rule is currently proposed, boilers that burn more than 10% coal with biomass will be classified in the coal subcategory; however, most such boilers will not be able to meet the coal subcategory CO emission standard for organic HAPs due to the substantial amount of biomass that they burn. Biomass fuels are more variable than coal and typically contain significantly more moisture than coal. As a result, it is more difficult to control combustion conditions in combination boilers than in boilers combusting only coal, which means that CO emissions from combination boilers often will be unavoidably greater than from a comparable coal-fired boiler. This makes the coal subcategory an inappropriate choice for establishing standards for combustion-based HAP. Regulating combustion-based HAP from combination boilers under the biomass subcategory makes more sense because combination boilers will perform more like biomass-fired boilers with regard to the combustion related HAPs.

On the other hand, biomass typically has lower levels of metals, halogens, and mercury than coal. As a result, regulating the fuel-related HAPs from combination boilers under the biomass subcategory would be inappropriate because the amount of co-fired coal would in many cases prevent combination boilers from meeting the standards for fuel-based HAPs. For this reason, it makes more sense to regulate fuel-based HAP emissions from combination boilers under the coal subcategory.

Response: Please refer to the preamble for discussion of combination fuel units.

Commenter Name: John Williams
Commenter Affiliation: Maine Pulp and Paper Association
Document Control Number: EPA-HQ-OAR-2002-0058-1913.1
Comment Excerpt Number: 8

Comment: Co-firing Fuels. The Maine Mills have concerns with the proposed unit subcategories with respect to units that burn multiple fuels. Certain boilers at the Mills burn greater than 10% fossil fuel on an annual basis; however, the units also burn a significant amount of biomass, including periods of 100% biomass. For some pollutants such as CO, the emissions profile is much different based on the fuel mix with higher emissions expected from burning biomass. Likewise, the proposed limit for CO for the coal subcategory is much lower than the proposed limit for the biomass subcategory; however, the unit would be restricted to meet only the lower coal limit, because it fires greater than 10% on an annual basis. EPA needs to consider alternate CO and dioxin/furan limits for sources that co-fire fossil fuels and biomass fuels.

Response: Please refer to the preamble for discussion of combination fuel units.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 3

Comment: A Pollutant-by-Pollutant Approach is Not Appropriate for Our Boilers

The air emissions profile of the many multi-fuel-fired boilers in the pulp and paper industry varies with fuel mix, making it difficult to establish a "typical" emissions profile. Many times boiler operators have emission limits that change based on the fuel fired. The fact that these boilers must often adapt quickly to varying process steam demand and experience frequent load swings also makes characterizing "typical" emissions difficult. Permitting changes to a multi-fuel fired boiler is challenging because predicting projected actual emissions following the change is difficult, as fuel mix can vary based on season, fuel cost, and operation of other equipment at the facility.
Air emissions control studies for multi-fuel-fired boilers can be difficult, as the control strategy and primary compound of concern vary with the fuel mix. Consider a pulp and paper mill boiler that burns fuel oil, biomass, and coal. Coal and biomass might produce the highest particulate emissions, but coal and fuel oil produce the highest SO2 and HCl emissions, and biomass may produce the highest CO emissions. Therefore, an ESP might be the most appropriate control device for wood firing, a wet scrubber might be the most appropriate control device for coal and oil firing, and control options like combustion improvements would have to be evaluated to reduce CO emissions from wood firing. It is our hope that future CO, VOC, and HAP limits are not so low that combustion improvements alone will not be enough to achieve compliance, as there are no reasonable add-on emissions control combinations for these compounds that make sense to implement on our boilers. For example, adding catalytic oxidation, considered by EPA as appropriate under this proposal, does not materially affect HAP emissions unless flue gas temperatures are at least 400°F. The use of CO catalysts as HAP control therefore requires reheating flue gases by 100°F or more, as they cannot likely be situated prior to particulate control devices. CO catalysts will also oxidize SO2 to SO3 and NO to NO2. This outcome is not practical, since it increases emissions, reduces efficiency, and moves away from both environmental and energy security objectives.

Under the proposed Boiler MACT regulation, the emission limits for each compound have been developed based on the best performing boilers for each compound, not the best overall performing boilers of each boiler type subcategory. Therefore, the boiler may have to install multiple emissions controls to account for the fact that it burns multiple fuels, each with a different emissions profile, and meet multiple fuel-based emission limits for multiple rules (MACT, NSPS, state regulations, and lower NAAQS). It is appropriate to consider multi-fuel-fired boilers differently than single fuel boilers in the context of boiler emissions regulations.

Response: Please refer to the preamble for discussion of combination fuel units. See preamble for discussion of pollutant-by-pollutant approach.

Commenter Name: Jack Carter
Commenter Affiliation: Weyerhaeuser Company
Document Control Number: EPA-HQ-OAR-2002-0058-2797.1
Comment Excerpt Number: 5

Comment: For combination fuel boilers where biomass is routinely a large portion of the fuel heat input but coal is the regulated fuel subcategory, EPA defines the coal subcategory in this rule to be when coal makes up at least 10% of the heat input, the proposed CO limit inadvertently incents increasing the proportion of coal heat input to more easily comply with the standard.

Response: Please refer to the preamble for discussion of combination fuel units.

Commenter Name: N/A
Commenter Affiliation: Sierra Club, Clean Air Task Force, Earthjustice, and Natural Resources Defense Council
Document Control Number: EPA-HQ-OAR-2002-0058-3187.1
Comment Excerpt Number: 5

Comment: EPA's Stated Bases for its Proposed Subcategories is Unsupported by the Data, and Internally Inconsistent, and Therefore Unreasonable and Arbitrary.

EPA's preamble statements and a brief discussion in the memorandum describing the floor setting exercise [See submittal for Reference 2.] are the only justification for its subcategories provided by the Agency in the record for this rule. Indeed, the supporting material for the information request underlying the rule simply assumes the continued use of the five subcategories for new and existing boilers as used in the 2004 rule, which the agency states are: "units designed to burn coal, units designed to burn biomass, units designed to burn liquid, units designed to burn natural gas/refinery gas, units designed to burn other process gases." Supporting Statement, Information Collection Request, NESHAP for Industrial, Commercial and Institutional Process Heaters, EPA-HQ-OAR2002-0058-0801, at 1.

A review of the few limited statements that are in the record for the proposal demonstrates that the arguments EPA puts forward to support its subcategories are themselves internally inconsistent, and unreasonable. For example, EPA asserts it has chosen fuel-based subcategories for what it calls the "fuel-dependent HAPs" – mercury, acid gases, and non-mercury metallic HAPs – because "data indicate that there are significant design and operational differences between units that burn coal, biomass, liquid, and gaseous fuels. Boiler systems are designed for specific fuel types and will encounter problems if a fuel with characteristics other than those originally specified is fired." 75 Fed. Reg. 32,017 (emphasis added). At the same time, however, when defining the various subcategories, EPA states, for example, that "if your new or existing boiler or process heater burns at least 10 percent coal on an annual average heat input basis, the unit is in one of the coal subcategories." Id. 32,012. This 10 percent rule or a variant of it defines all the fuel-based subcategories EPA uses. But a unit that burns, say, 12 percent coal is burning 88 percent something else, by definition. So, the HAPs it emits are would seem as or more likely to be dependent on the 88 percent of non-coal fuel being burned. And, if EPA's design and operational justifications (that boiler design and operation is very specific to fuel type) are correct, a unit burning 10 percent coal and 90 percent of some other fuel, which EPA's subcategories define as a "coal-fired" unit, should regularly "encounter problems." EPA nowhere explains this inconsistency -- either EPA's statements about the fuel-specific nature of boiler design and operation are not correct, or EPA has proposed MACT standards that will apply to boilers that by their nature are "encountering problems" due to their fuel mix.

Response: Please refer to the preamble for discussion of combination fuel units. See final rule and preamble for discussion of how units are assigned to subcategories and provisions available to switch subcategories.

Commenter Name: G. Vinson Hellwig and Robert H. Colby
Commenter Affiliation: National Assocation of Clean Air Agencies
Document Control Number: EPA-HQ-OAR-2002-0058-2841.1
Comment Excerpt Number: 6

Comment: While the MACT floors are calculated based on the fuel consumed during the test, the EPA section 112 proposal sets out a different test for determining which limit would apply to a particular unit in the future. EPA calls this test a "designed to combust" test, asserting that the limits will apply depending on the nature of the fuel that a unit is designed to combust. However, any unit that burns a fuel must be "designed" to combust that fuel and units that combust multiple fuels are, in fact, designed to combust each of those fuels. Under the proposal, the applicability of different limits is based on whether a source has combusted a prescribed amount of a type of fuel, not necessarily the fuel it combusts during a compliance test, and not the fuel that might be expected to dominate its current emissions profile. Thus, a unit would be "designed to combust" coal if at some unspecified time it generated at least 10 percent of its annual heat input from coal. EPA's proposal continues with a tiered system where, if the source did not burn 10 percent coal, it would look to see if it burned more than 10 percent biomass, and if it did, it would be subject to the biomass limits. If a source burned less than 10 percent solid fuel and any liquid fuel at all, it would be subject to the limits for liquid-fired units (even if it obtained 99.9 percent of its heat input from natural gas). Under this scheme a unit would be a coal-fired unit,[The proposal does not set out how the percentage of annual heat input is to be determined, but sources will need to know in advance of the commencement of a given year which limits apply to operations during that year] subject to the emission limitations based on the emission profile of coal-burning units, even if today it is burning 100 percent biomass. This would result in a situation where the CO limit is unattainable at the source, while the mercury and hydrogen chloride (HCl) limits are overly lax. This scheme also unfairly affects those who co-fire natural gas and oil, since the combustion of any oil at all would remove the exemption from emission limitations that EPA proposes for natural gas-fired units.

The proposal does not set out a rationale for this new approach or why the procedures set out in the vacated rule to address fuel mixtures are inadequate. NACAA recommends that MACT limits be established for each major category of fuels and that the procedures found at 40 CFR 63.7530 be used to address fuel mixtures.

Response: Please refer to the preamble for discussion of combination fuel units.

Commenter Name: N/A
Commenter Affiliation: Sierra Club, Clean Air Task Force, Earthjustice, and Natural Resources Defense Council
Document Control Number: EPA-HQ-OAR-2002-0058-3187.1
Comment Excerpt Number: 7

Comment: With respect to the degree to which units can fuel-switch between liquid and gaseous fuels or between such fuels and solid fuels, EPA strings several conflicting sentences together in the preamble that belie the conclusion it reaches that changing fuel type requires extensive changes to boiler systems. The Agency says "[w]hile many boilers in the population data base are indicated to co-fire liquids or gases with solid fuels, in actuality most of these commonly use fuel oil or natural gas as a startup fuel only, and operate on solid fuel during the remainder of their operation. In contrast, some co-fired units are specifically designed to fire combinations of solids, liquids, and gases." 75 Fed. Reg. 32,017. Data in the floors memorandum, by contrast shows that "many boilers and process heaters are designed to burn multiple fuel types," indeed, "some units reported test burns on more than one material" including the switch between tests between gas and liquid fuels (burned during periods of 'gas curtailment'). Floor Memo at 4. Clearly the distinction between boiler types on the basis of fuels burned, viewed in the best light possible, is not as dramatic as EPA describes – it certainly does not justify EPA's choice of subcategories. EPA's rationale is substantively empty, and therefore unreasonable. Moreover, that fact suggests EPA's real motivation – to define subcategories not by "class, type, and size" as the statute requires, but so that the resulting MACT floors are achievable by the majority of ICIBPH. That rationale is unlawful.

Response: Please refer to the preamble for discussion of combination fuel units. See final rule and preamble for discussion of how units are assigned to subcategories and provisions available to switch subcategories.

Commenter Name: Tim Keneally
Commenter Affiliation: KapStone Paper and Packaging Corporation
Document Control Number: EPA-HQ-OAR-2002-0058-2673.1
Comment Excerpt Number: 8

Comment: EPA must adjust the proposed subcategories to properly accommodate the unique characteristics of combination boilers. Both of our cogeneration boilers co-fire coal in an amount greater than 10% heat input basis with greater than 10% biomass. As a result, they do not fit cleanly into either the coal-fired boiler subcategory or the biomass-fired boiler subcategory. To better accommodate the actual performance of combination boilers, we recommend that EPA create another subcategory so that they belong to the coal subcategory for purposes of regulating the fuel-based HAP (i.e., metals/PM, HAP acid gases, and mercury) and the biomass subcategory for purposes of regulating the combustion-based HAP (i.e., CO (as a surrogate for organic HAPs) and dioxins/furans).

Response: Please refer to the preamble for discussion of combination fuel units.

Commenter Name: Stephen R. Gossett
Commenter Affiliation: Eastman Chemical Company
Document Control Number: EPA-HQ-OAR-2002-0058-3137.1
Comment Excerpt Number: 10

Comment: The proposed definition of any boiler burning at least 10% coal is a coal-fired boiler results in non-representative emission standards and is unfair to boilers predominantly fired with coal.

EPA has arbitrarily decided to categorize combination type boilers that burn at least 10 percent coal as a coal-fired boiler. They then included emission data from such boilers along with 100 percent coal-fired boilers to establish standards for new and existing sources. This is inherently unfair to both biomass and coal fired boilers. Coal-fired boilers will inherently have higher emissions of HCl and mercury whereas biomass boilers will inherently have higher CO emissions. Eastman recommends EPA reverse its methodology and only use data from boilers burning at least 90 percent coal to set standards for the coal subcategories and to use data from boilers burning less than 10 percent coal to set standards for the biomass subcategories. For combination boilers, EPA should allow compliance to be determined using weighted averages such as in NSPS Db where EPA used this methodology for sulfur dioxide and NOx. We do not see any issues related to enforceability of such weighted average standards that cannot be overcome with today’s information technology.

Response: Please refer to the preamble for discussion of combination fuel units.

Commenter Name: Sharene Shealey
Commenter Affiliation: RRI Energy
Document Control Number: EPA-HQ-OAR-2002-0058-2759.1
Comment Excerpt Number: 10

Comment: EPA must clarify whether the definitions for boiler subcategories are based on actual fuel firing or permitted fuel firing and over what time period the annual average should be taken.

RRI Energy owns and/or operates several ICI boilers that are capable of and permitted to burn multiple fuels, generally fuel oil or natural gas. In all cases where units are permitted to burn two fuels, the units typically only fire one fuel. For example, the auxiliary boilers at Conemaugh Station, Aux Boiler A and Aux Boiler B, are permitted to burn either No. 2 Fuel Oil or Natural Gas. Aux Boiler B was installed in 2006 and only fired fuel oil during the start-up/shakedown and testing phase of operation, all of which occurred in 2006. This boiler has not since fired fuel oil; in practice it is a natural gas-fired boiler. In 2006 though, because of start-up/shakedown and required testing, 14.8% of this boiler's heat input was due to fuel oil firing. This boiler has not combusted any fuel other than natural gas since start-up was completed. RRI Energy considers this boiler to be gas-fired, and believes it should be regulated as such. We are requesting that EPA clarify whether the actual practice or permit conditions define the fuel and we request clarification on the use of the term "annual average".

RRI strongly believes that practice should dictate the boiler's subcategory and that at least two years of data be included in determining the annual average fuel contributions.

Response: See the preamble and final rule for modified provisions available to switch between subcategories. In the final rule the term 'heat input on an annual average' contained within each of the subcategories was switched to 'annual heat input'.

Commenter Name: Robert R. Scott
Commenter Affiliation: New Hampshire Department of Environmental Services, Air Resources Division
Document Control Number: EPA-HQ-OAR-2002-0058-2734.1
Comment Excerpt Number: 11

Comment: NHDES also considers the approach of categorizing boilers based on one primary fuel type to be problematic for enforceability. Boilers today are often configured to run on multiple fuels and the percentage of any one particular fuel over another can be based in part on the cost of each fuel. Therefore, a boiler that would be considered part of one sub-category based on the previous year's annual heat input could be operating under an entirely different fuel loading scenario the following year. Also, without detailed requirements for tracking, recordkeeping and reporting, the 10% annualized usage number would be difficult for enforcement staff to verify. For example, if a biomass boiler co-fired with oil were to perform a stack test for CO, it would be required to meet the 100 ppm (@7% 0?) standard even if during the stack test it burned 99% oil, simply because it burned any amount of biomass. Since a precedent has been set in 40 CFR 60 with establishing emission limitations based on a weighted average between different fuel types, NHDES recommends that EPA provide this same mechanism in order to determine the applicable emission limitations for multi-fuel fired boilers.

Response: Please refer to the preamble for discussion of combination fuel units.

Commenter Name: Robert R. Scott
Commenter Affiliation: New Hampshire Department of Environmental Services, Air Resources Division
Document Control Number: EPA-HQ-OAR-2002-0058-2734.1
Comment Excerpt Number: 12

Comment: As an alternative, EPA could clarify in the regulation that if a device is operating under a dual fuel scenario, the device must comply with the lowest emission limit for each fuel burned. However, NHDES is concerned that by requiring multi-fuel fired units to comply with the lowest emission limit for each fuel type burned, this proposal would inadvertently push units into fuel switching situations that may result in boilers being required to meet more lenient standards. Therefore, NHDES also recommends that EPA encourage fuel switching not between solid and gaseous fuels but between "dirtier" and "cleaner" burning forms of the same fuel.

Response: Please refer to the preamble for discussion of combination fuel units.

Commenter Name: Arthur N. Marin
Commenter Affiliation: NESCAUM
Document Control Number: EPA-HQ-OAR-2002-0058-2893.1
Comment Excerpt Number: 19

Comment: EPA proposes allowing a facility to use up to 10% of an alternative fuel that a boiler is “designed” to burn without having to comply with the appropriate emission limit. NESCAUM finds this language problematic for several reasons. First, we suggest that EPA change the word “designed” to “permitted” to burn. While a unit may be designed to burn certain fuels, a state may have placed limitations on fuel use within a permit. Second, we have concerns with the 10% fuel use limit, as it creates significant enforcement issues. Without detailed requirements for tracking, recordkeeping, and reporting, the 10% limit will be difficult for enforcement staff to verify. Third, facilities’ use of the different fuels may vary from year to year, which leads to different emission limits from year to year. States would be unclear as to how to determine which emission limits would apply and when. Fourth, there are questions about what limits would apply when a boiler is simultaneously burning more than one fuel. NESCAUM recommends that EPA modify the rule to state that if a facility combusts more than one fuel type, it must meet the lowest applicable emission limit for the fuel types actually burned.

Response: Please refer to the preamble for discussion of combination fuel units.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 154

Comment: Within the pulp and paper sector, there are a number of boilers (at least 30, based on the survey database developed by EPA) that co-fire coal in an amount greater than 10% heat input basis with at least 5% biomass. These combination boilers that simultaneously burn coal and biomass have different emission profiles than units that burn coal or units that burn biomass. As a result, we recommend EPA utilize a combination of the coal subcategory and biomass subcategory emission standards for these units.
As the rule is currently proposed, boiler units that burn more than 10% coal with biomass will be classified in the coal subcategory; however, they will not be able to meet the coal subcategory CO emission standard for organic HAPs due to the substantial amount of biomass that they burn. If these units cannot comply with the CO standard, these units may have to switch away from biomass and burn more coal to be able to comply with the coal subcategory emission standards AF&PA notes that some boilers would not be able to switch fuels in the other direction (i.e., burn more biomass to become classified as a biomass boiler). Many boilers are designed to meet its rated steam load burning a designated fuel mix of coal and biomass. If the amount of biomass was increased significantly, the steam load would drop since biomass is a lower BTU fuel than coal resulting in a shortage of steam for the pulp and paper (or wood products) process.. This unintended consequence of replacing biomass with coal is contrary to national energy and climate policy, which encourages the use of more renewable biomass fuel.
We recommend the emission standards for coal/biomass combination boilers utilize a combination of the emission standards developed for the coal subcategory and for the biomass subcategory. Combination boilers burning more than 10% coal with biomass should be subject to the same emission standards for PM/metals, mercury, and HCl as the coal subcategory since the emissions of these pollutants are fuel dependent and will be driven primarily by burning coal. However, for all the following reasons, these combination boilers should be subject to the biomass subcategory emission limitations for organic HAP (CO and dioxins/furans).

Response: Please refer to the preamble for discussion of combination fuel units.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1

Comment Excerpt Number: 156

Comment: A combination boiler that co-fires biomass and coal will have a different CO emissions profile than a boiler that burns only coal. The CO emissions profile of these combination boilers will be like that of a boiler in the biomass subcategory for the following reasons:
* Wet biomass fuels (e.g., bark or hog fuel) have more variation in fuel quality and as such do not burn as evenly as coal. This variability results in higher CO emissions than coal combustion. This fact is recognized by EPA in the subcategorization of boilers burning these different fuels. The majority of biomass fuels burned by the pulp and paper industry are wet fuels, and the moisture content varies depending on the source of the fuel, the weather conditions (e.g., rainfall on outdoor storage piles), and the type of fuel (bark, sawdust, wood chips, etc.). Higher moisture fuels, as well as variations in moisture content, cause less even combustion and therefore, higher CO emissions.
* Many pulp and paper industry combination boilers burn wood residues from their wood yard operations, which do not run continuously. As such, the amount of wood residue burned varies throughout each day, as does the type of wood residue (bark, sawdust, undersized chips). Such variations in the fuel quality, size, and type cause less consistent combustion and therefore, higher CO emissions.
* EPA recognizes that wet fuels or varying moisture content of the fuel can result in incomplete combustion, and that the design of the unit influences organic HAP emissions. Specifically, the preamble to the proposed rule states:
"The design of the boiler or process heater, which is dependent in part on the type of fuel being burned, impacts the degree of combustion. Boilers and process heaters emit a number of different types of HAP emissions. Organic HAP are formed from incomplete combustion and are influenced by the design and operation of the unit." [35 FR 32017].

For establishing the organic HAP emission standards for combination boilers, we also considered and then dismissed a prorated approach. The prorated approach we considered involved the use of a sliding scale to prorate the biomass organic HAP emissions based on the quantity of biomass being co-fired over a 30-day averaging period. We did not favor a prorated approach for the following reasons:
* The amount of biomass material combusted would be accrued at the end of the averaging period. Once the amount of biomass combusted over the averaging period is determined, the source would calculate the prorated organic HAP limits for that averaging period. The limits to be complied with and the source's compliance status would be known "after the fact". Not knowing what limits a source needed to be complying with and not knowing compliance status until "after the fact" is untenable. Sources would essentially be "flying blind" as they would not know what their limits were until the end of the averaging period. We did not feel this was an acceptable approach.
* Many sources utilize inventory and purchase records for determining fuel throughput into the boiler units. On a longer term averaging basis, such as on an annual basis, this method of determining fuel throughput is reasonably accurate. This approach may not provide accurate estimates on a short term average basis and facilities may have to install more accurate metering or fuel throughput monitoring equipment at an additional cost.

* The prorated approach does increase the administrative burden of an already burdensome rule by requiring additional data collection, recordkeeping and reporting.
* Prorating may not be workable for combination boilers that co-fire liquid fuel and biomass since the organic HAP proposed limits for the liquid fuel sub-category are very stringent.
For the reasons given above, coal/biomass combination boilers will not be able to meet the proposed coal stoker, pulverized coal, and coal FBC limits of 50 ppm, 90 ppm, and 30 ppm CO, respectively. The proposed biomass stoker CO limit of 560 ppm is a more appropriate limit for stoker and pulverized coal combination boilers, and the proposed biomass FBC limit of 250 ppm CO is a more appropriate limit for combination FBC boilers. Adopting the biomass subcategory organic HAP emission limits (CO and dioxin) for coal/biomass combination boilers would establish more achievable limits for these boilers given the variability of the biomass fuels and boiler operating/design conditions.

Response: Please refer to the preamble for discussion of combination fuel units.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 157

Comment: In order for EPA to adopt a combination of the coal subcategory and biomass subcategory emission limits for coal/biomass combination boilers, the proposed definitions of unit designed to burn biomass subcategory and unit designed to burn coal subcategory would have to be modified. We suggest that they be modified as follows:
Unit designed to burn biomass subcategory
i. For compliance with PM, HCl, and mercury standards, includes any boiler or process heater that burns at least 10 percent biomass, but less than 10 percent coal, on a heat input basis on an annual average, either alone or in combination with liquid fuels or gaseous fuels.
ii. For compliance with the CO and dioxin emission standards, includes
a. any boiler or process heater that burns at least 10 percent biomass, but less than 10 percent coal, on a heat input basis on an annual average, either alone or in combination with liquid fuels or gaseous fuels; and
b. any boiler or process heater that burns at least 5 percent biomass on a heat input basis on an annual average in combination with coal, liquid or gaseous fuels and that does not fall under the coal, gas1, gas2, or liquid fuel subcategories.
Unit designed to burn coal subcategory
i. For compliance with the PM, HCl, and mercury standards, includes any boiler or process heater that burns any coal alone or at least 10 percent coal on a heat input basis on an annual average in combination with biomass, liquid fuels, or gaseous fuels.
For compliance with the CO and dioxin standards, includes any boiler or process heater that burns any coal alone or at least 10 percent coal on a heat input basis on an annual average in combination with biomass, liquid fuels, or gaseous fuels, excluding those boilers or process heaters that burn at least 5 percent biomass on a heat input basis on an annual average.

Response: Please refer to the preamble for discussion of combination fuel units.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 268

Comment: We agree in general with EPA's rationale that boilers should be subcategorized based on their fuel type and design; however, we do not agree that all boilers are designed to burn only one fuel type and that they will encounter operational problems if another fuel type is fired at more than 10 percent of heat input. Some boilers are specifically designed to burn a combination of fuels, and to burn them in varying quantities. According to one vendor who designs and builds boilers for various industries, 84% of the boilers are designed to fire combinations of fuels at any one time. In some cases, these boilers are not able to reach full load on any single fuel. From this information it would seem that EPA has incorrectly presumed that boilers are designed based on a primary fuel. Rather, boilers can be designed to fire a variety of fuels, encompassing various types of solid, liquid, and gaseous fuels. This practice provides the most flexibility to facilities and allows them to select fuel mix based on various factors that include cost, availability, season, weather, etc. The subcategories of boilers should not be based on the fuel a boiler or process heater is designed to burn, but rather the fuel the unit actually burns. With that said, EPA should clarify how and when units would move between subcategories in the rule based on the actual fuel mix fired and how and when compliance would be demonstrated for a different subcategory than the one the unit was under for the initial compliance demonstration.

Response: Please refer to the preamble for discussion of combination fuel units. See final rule and preamble for discussion of how units are assigned to subcategories and provisions available to switch subcategories.

Commenter Name: Robert R. Scott
Commenter Affiliation: New Hampshire Department of Environmental Services, Air Resources Division
Document Control Number: EPA-HQ-OAR-2002-0058-2734.1
Comment Excerpt Number: 10

Comment: EPA proposes allowing a facility to use up to 10% of an alternative fuel that a boiler is "designed" to burn without having to comply with appropriate emission limits. NHDES suggests that EPA change the word "designed" to "permitted" to burn. While a unit may be designed to burn certain fuels, a state may have placed limitations on the type of fuel used within a permit.

Response: Please refer to the preamble for discussion of combination fuel units.

Commenter Name: James P. Brooks
Commenter Affiliation: Maine Department of Environmental Protection, Bureau of Air Quality
Document Control Number: EPA-HQ-OAR-2002-0058-2746.1
Comment Excerpt Number: 13

Comment: The Maine DEP has several multi-fuel boilers that do not neatly fit into EPA's proposed categories of units "designed to burn" coal, biomass, or oil. These units are licensed to burn all three fuel types, and vary the amount of each fuel type burned based on availability, price, and demands on the boiler systems. Some of these units were originally designed many decades ago for one fuel type but have been subsequently modified to accommodate others. Does "designed to burn" mean licensed to burn, or how the unit was originally designed by the manufacturer?

Response: Please refer to the preamble for discussion of combination fuel units.

Commenter Name: Stephen R. Gossett
Commenter Affiliation: Eastman Chemical Company
Document Control Number: EPA-HQ-OAR-2002-0058-3137.1
Comment Excerpt Number: 40

Comment: Expressing limits as applicable to units "designed" to burn certain fuels is problematic. For example, a unit designed to burn Gas 2 may elect not to burn Gas 2 and should not otherwise be interpreted to be subject to the Gas 2 standards.

Response: Please refer to the preamble for discussion of combination fuel units.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 155

Comment: We agree in general with EPA's rationale that boilers should be subcategorized based on their fuel type and design; however, we do not agree that all boilers are designed to burn only one fuel type and that they will encounter operational problems if another fuel type is fired at more than 10 percent of heat input. Some boilers are specifically designed to burn a combination of fuels, and to burn them in varying quantities. Pulp and paper industry coal/biomass combination boilers burn varying amounts of biomass and coal depending on factors such as fuel availability, wood fuel moisture, fuel cost, malfunctions in the fuel feed systems, and residuals management obligations. Also, the pulp and paper industry combination boilers that meet the proposed definition of a pulverized coal boiler burn pulverized coal like a traditional pulverized coal boiler and simultaneously burn biomass fuels on a stoker grate. Other combination boilers burn pulverized coal or petroleum coke along with biomass in a fluid bed combustor type of boiler. According to one vendor who designs and builds boilers for this and other industries, 84% of the boilers are designed to fire combinations of fuels at any one time. In some cases, these boilers are not able to reach full load on any single fuel. From this information it would seem that EPA has incorrectly presumed that boilers are designed based on a primary fuel. Rather, boilers can be designed to fire a variety of fuels, encompassing various types of solid, liquid, and gaseous fuels. This practice provides the most flexibility to facilities and allows them to select fuel mix based on various factors that include cost, availability, season, weather, etc. Combination boilers can sometimes burn 100% coal, 100% biomass, 100% liquid fuel, or 100% gaseous fuel, but typically burn mixtures of these fuels, based on various operational and economic factors. There is a difference between the worst case fuel a unit is permitted to burn or is capable of burning and the fuel mixture a unit will burn on an annual basis, so subcategory assignments should be based on actual fuel usage.

Response: Please refer to the preamble for discussion of combination fuel units.

Commenter Name: Mary Graham
Commenter Affiliation: Charleston Metro Chamber of Commerce
Document Control Number: EPA-HQ-OAR-2002-0058-2732.1
Comment Excerpt Number: 4

Comment: EPA must adjust the proposed subcategories to properly accommodate the unique characteristics of combination boilers. Within certain industry sectors, boilers are commonly used that co-fire coal in an amount greater than 10% heat input basis with at least 10% biomass. These "combination boilers" that simultaneously burn coal and biomass have different emission profiles than units that burn coal or units that burn biomass. As a result, combination boilers do not fit cleanly into either the coal-fired boiler subcategory or the biomass-fired boiler subcategory. To better accommodate the actual performance of combination boilers, we recommend that EPA adjust the proposed subcategory for combination boilers so that they belong to the coal subcategory for purposes of regulating the fuel-based HAP (i.e., metals/PM, HAP acid gases, and mercury) and the biomass subcategory for purposes of regulating the combustion-based HAP (i.e., CO (as a surrogate for organic HAPs) and dioxins/furans).

Response: Please refer to the preamble for discussion of combination fuel units.

Commenter Name: David A. Buff
Commenter Affiliation: Golder Associates Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2801.1
Comment Excerpt Number: 9

Comment: The FSI has one mill (in Hawaii) that burns both coal and bagasse in its three boilers. These boilers operate at times on bagasse only, coal only (mainly during the sugarcane processing off-season), and a combination of coal and bagasse. EPA is proposing to define boilers that burn at least 10 percent coal (on an annual heat input basis) as being in one of the coal subcategories (see pg. 32017). This is appropriate for fuel-based HAP, but not for organic HAP. Whenever a significant amount of bagasse is being burned in a boiler (>10 percent heat input), the resulting organic HAP emissions are significantly higher than when burning coal (or other fossil fuel) alone, making it impossible to meet organic HAP emission limits for coal-only burning. The higher the percentage of bagasse burned, the more influence on the overall organic HAP emissions. Therefore, FSI requests that any boiler burning bagasse (or biomass) at greater than 10 percent annual heat input basis be placed in the bagasse boiler (or biomass boiler) subcategory, and not in a fossil fuel subcategory.

Within certain industry sectors, boilers are commonly used that co-fire coal in an amount greater than 10 percent heat input basis with at least 10 percent biomass. These “combination boilers” that simultaneously burn coal and biomass have different emission profiles than units that burn coal or units that burn biomass. As a result, combination boilers do not fit into either the coal-fired boiler subcategory or the biomass-fired boiler subcategory. To better accommodate the actual performance of combination boilers, we recommend that EPA adjust the proposed subcategory for combination boilers so that they belong to the coal subcategory for purposes of regulating the fuel-based HAP (i.e., metals/PM, HAP acid gases, and Hg) and the biomass subcategory for purposes of regulating the combustion-based HAP [i.e., CO (as a surrogate for organic HAPs) and dioxins/furans].

Response: Please refer to the preamble for discussion of combination fuel units.

Commenter Name: David A. Buff
Commenter Affiliation: Golder Associates Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2801.1
Comment Excerpt Number: 10

Comment: As the rule is currently proposed, boilers that burn more than 10 percent coal with biomass will be classified in the coal subcategory; however, most such boilers will not be able to meet the coal subcategory CO emission standard for organic HAPs due to the substantial amount of biomass that they burn. Biomass fuels are more variable than coal and typically contain significantly more moisture than coal. As a result, it is more difficult to control combustion conditions in combination boilers than in boilers combusting only coal, which means that CO emissions from combination boilers often will be unavoidably greater than from a comparable coal-fired boiler. This makes the coal subcategory an inappropriate choice for establishing standards for combustion-based HAP. Regulating combustion-based HAP from combination boilers under the biomass subcategory makes more sense because combination boilers will perform more like biomass-fired boilers with regard to the combustion related HAPs.

On the other hand, biomass typically has lower levels of metals, halogens, and Hg than coal. As a result, regulating the fuel-related HAPs from combination boilers under the biomass subcategory would be inappropriate because the amount of co-fired coal would in many cases prevent combination boilers from meeting the standards for fuel-based HAPs. For this reason, it makes more sense to regulate fuel-based HAP emissions from combination boilers under the coal subcategory.

Response: Please refer to the preamble for discussion of combination fuel units.

Commenter Name: Randall D. Quintrell
Commenter Affiliation: Georgia Paper and Forest Products Association, GPFPA
Document Control Number: EPA-HQ-OAR-2002-0058-2905
Comment Excerpt Number: 21

Comment: For multifuel boilers under the proposed Rule the unit can only be in one classification, even though the characteristics of two subcategories exist and both predominate. In the case of using more than 10% coal, the coal classification is primary. However, for CO, using the coal conditional maximum for what is essentially a large percent biomass boiler is likely an impossible standard to meet. The Rule must be modified to address multifuel boilers to bifurcate the emission limits, with fuel based emissions (PM, HC1, Hg) based on the coal classification and combustion based emissions (CO, dioxin/furan) based on the biomass classification. Alternatively, additional subcategories to address various multi-fuel boiler configurations must be added to the Rule.

Response: Please refer to the preamble for discussion of combination fuel units.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 62

Comment: The special case of units that fire both gas and liquid in the same burners needs to be addressed.
Many boilers and process heaters at refineries that do not have natural gas access are designed to be able to burn gas and liquid in any combination, as are some boilers and process heaters in other refineries. A picture of a standard John Zink combination design appears below, with an oil gun in the center, surrounded by gas burners.

[See submittal for image of a typical combination gas and oil burner.]

EPA, in establishing its gas and liquid subcategories, does not appear to have considered this type of combination operation. The Agency states on page 32017 of the preamble:

“These subcategories are based on the primary fuel that the boiler or process heater is designed to burn. We are aware that some boilers burn a combination of fuel types or burn a different fuel type as a backup fuel if the primary fuel supply is curtailed. However, boilers are designed based on the primary fuel type (and perhaps to burn a backup fuel) and can encounter operational problems if another fuel type that was not considered in its design is fired at more than 10 percent of the heat input to the boiler.”

This combination burner design is specifically designed so that it can fire up to 100% oil or gas or fire both in varying quantities on the same burner. They are a completely different design than EPA contemplated in setting its standards and cannot be fairly included in the same subcategory with other units.

There are several aspects of the co-firing design that are significant from a combustion perspective. First, when a burner is operating on both gas and oil, the gas flame can rob the oil gun of oxygen and result in higher CO emissions. Second, the need to fire up to 100% of the fuel in a heater or boiler as either oil or gas means that the firebox design cannot be optimized to maximize combustion efficiency. As a general rule, a firebox is designed to be about 2/3rds of the flame height of fuel being fired. However, this is not possible in a co-fired unit, because of the different heights and characteristics of oil and gas flames:

[See submittal for image of photographs showing differing flame characteristics of liquid and gas flames in a unit with combined oil/gas burners.]

The result is that the process heater/boiler firebox configurations for such co-fired units are a compromise which does not maximize combustion efficiency or NOx emissions because it cannot be designed to do so.

For these reasons, boilers and process heaters with combination burners should be in their own subcategory.

Recommendation: Establish a subcategory for gas/liquid boilers and process heaters which use combination.

Recommendation: Apply the tune-up work practice requirements to gas’liquid boilers and process heaters which use combination burners.

Response: Please refer to the preamble for discussion of combination fuel units.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-2702.1

Comment Excerpt Number: 99

Comment: Table 1 and 2 Emissions Limits
Combination Fuels.
Under the Proposed Rule, boiler units that burn more than 10 percent coal with biomass will be classified in the coal subcategory. 75 FR 32065. The 10 percent threshold established by EPA is arbitrary and EPA has failed to justify it as an appropriate threshold for defining a primary fuel. EPA then included emission data from such boilers along with 100 percent coal-fired boilers to establish standards for new and existing sources. This is inherently unfair to both biomass and coal fired boilers. Coal-fired boilers will inherently have higher emissions of HCl and mercury whereas biomass boilers will inherently have higher CO emissions.

This threshold is especially problematic for units that burn biomass with coal. If these predominantly biomass burning units exceed the arbitrary 10 percent threshold, they will be required to comply with the coal subcategory emission standard for CO. Such units are unable to meet the CO emission standard for coal. CIBO recommends that EPA amend the Proposed Rule to include an additional subcategory for combination boilers that burn both coal and biomass. EPA should reverse its methodology and only use data from boilers burning at least 90 percent coal to set standards for the coal subcategories and to use data from boilers burning less than 10 percent coal to set standards for the biomass subcategories. For combination boilers, EPA should allow compliance to be determined using weighted averages such as in NSPS Db where EPA used this methodology for sulfur dioxide and NOx. We do not see any issues related to enforceability of such weighted average standards that cannot be overcome with today's information technology. Another option is for EPA to apply the CO and dioxins/furans emission limits for the biomass subcategory to units in this new subcategory.

Such an approach is justified for a variety of reasons. First, if units that co-fire biomass and coal cannot comply with the CO standard it is likely they will switch away from biomass and burn more coal to be able to comply with the coal subcategory emission standards. Discouraging the use renewable biomass fuel is contrary to current U.S. energy policy.

Response: Please refer to the preamble for discussion of combination fuel units.

Commenter Name: Cynthia L. Karlic
Commenter Affiliation: NRG Energy, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2822.1
Comment Excerpt Number: 1

Comment: NRG owns and operates several boilers which may be considered gas-fired ICI boilers under the proposed ICI MACT rule. Some of the boilers have dual fuel-firing capability utilizing natural gas and liquid fuel. These dual fuel-fired boilers could fall under the "Unit designed to burn gas 1 (NG/RG) subcategory ("Gas ICI Boiler"). However, the ICI MACT rule states that the "Unit designed to burn gas 1 (NG/RG) subcategory includes any boiler or process heater that burns at least 90 percent natural gas and/or refinery gas on a heat input basis on an annual average."

The use of the 90% heat input criteria on an annual basis to determine if an ICI boiler is a Gas ICI Boiler may be problematic for the dual fuel-fired boilers because in any individual year the boiler may have a gas-fired heat input less than the 90% criteria. This would cause the boiler to be in the Gas ICI Boiler subcategory for a year, in the "Unit designed to burn oil" subcategory ("Oil ICI Boiler") in a subsequent year, and then back to the Gas ICI Boiler in a third year. Changing categories on an annual basis based on a single year's heat input is impractical and may lead to compliance issues for both the regulated source and regulators.

Response: Please refer to the preamble for discussion of combination fuel units.

Commenter Name: Dennis A. Werblow
Commenter Affiliation: Decorative Panels International, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2599.1
Comment Excerpt Number: 2

Comment: DPI's Alpena plant requires significant energy resources from three industrial boilers to produce the steam and power requirements for its hardboard process. All three exhaust through a common stack. Each of the boilers is permitted to burn multiple fuels, although two of the boilers are primarily coal fired and the third is primarily wood fired. Alternative fuels include natural gas, used oils and biomass materials such as wood dust, bark, and wastewater treatment sludge. The air emissions profile of multi-fueled boilers varies with fuel mix and moisture contents, making is difficult to establish a "typical" emissions profile. The fact that these boilers must often adapt quickly to varying process steam demand and experience frequent load swings also makes characterizing typical emissions difficult.

Response: Please refer to the preamble for discussion of combination fuel units.

Commenter Name: Sean M. O'Keefe
Commenter Affiliation: Alexander and Baldwin, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-3196
Comment Excerpt Number: 3

Comment: Biomass-fired boilers should not be required to meet standards that are based on emissions from boilers firing coal; EPA needs to modify its approach to regulation of "combination boilers" burning multiple fuels.
The proposed rule would place in the "unit designed to burn coal subcategory" any boiler that burns coal alone or that burns at least ten percent coal on an annual heat input basis in combination with biomass, liquid fuels, or gaseous fuels. Any boiler in this subcategory would be required to meet standards that are based on emissions from the best-performing sources in

the subcategory, as measured during coal firing. These emissions limits would have to be met at all times when the boiler is operating, regardless of what fuel is being fired. A&B believes that this approach is fundamentally flawed because it establishes emissions limits for boilers firing biomass fuels that are based on the emissions performance of boilers firing coal, a fuel with a vastly different emissions profile.

The Puunene Mill boilers fire primarily renewable biomass fuel, sugarcane bagasse produced in the mill, which typically comprises 60 to 70 percent of the annual heat input to the three boilers. [Since 2001, when the plantation closed its sugar mill at Paia and converted to single mill operation, bagasse has accounted for just over 71 percent of the annual average heat input to the Puunene Mill boilers. Historically, the boilers have been categorized in their permits to operate and/or under state air pollution control regulations as "biomass boilers" with a minimum of 50 percent of the annual heat input to each boiler coming from biomass fuel.] In order to meet its power generation commitments during maintenance periods when bagasse is not being produced by the mill, and to allow stabilization of the boilers during fluctuations in biomass fuel quality or when the bagasse supply to the boilers is temporarily interrupted, the boilers also fire limited amounts of coal, both alone and in combination with biomass. Thus, despite the fact that the Puunene Mill boilers were constructed at an operating sugar mill for the purpose of generating steam by burning bagasse produced by the mill, under the proposed rule these boilers would be categorized as "stokers designed to burn coal" and would be required to meet the corresponding emissions limits in the proposed rule, including a carbon monoxide (CO) emission limit of 50 ppm by volume (corrected to three percent oxygen), at all times, including when firing biomass fuels.

Response: Please refer to the preamble for discussion of combination fuel units.

Commenter Name: Sean M. O'Keefe
Commenter Affiliation: Alexander and Baldwin, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-3196
Comment Excerpt Number: 4

Comment: Sugarcane bagasse typically contains approximately 50 percent moisture, as fired, though moisture can range as high as 55 to 60 percent depending upon mill operations and harvesting conditions. Bagasse is produced as the sugarcane is ground in the mill and is routed directly from the mill to the boilers to be combusted. Thus, any fluctuations in mill operations or in the quality of cane being milled are directly and immediately transmitted to the boilers in the form of fluctuations in fuel quality, including fuel moisture. By comparison, coal burned at HC&S has a moisture content of ten percent or less, with very little variation. The high moisture content and variability of the bagasse fuel, combined with design characteristics of the boilers developed to burn this fuel, result in CO emissions from burning bagasse (and many other biomass fuels) that are typically one to two orders of magnitude higher than those generated by burning coal in the same boilers. [See, for example, the discussion of bagasse boiler CO emissions in Boiler MACT Report - Bagasse Boilers Should be Regulated in a Separate Subcategory under the Boiler MACT Rules Because they are a Unique Class of Boilers (Golder

Associates; July 2010) and CO emissions data for bagasse fired boilers included in MACT Floor Analysis for Bagasse Boiler Subcategory (Golder Associates; August 2010), both of which have been submitted to the docket for this rule, and emissions data from coal firing in Puunene Boiler 3 (identified as a "best performing unit" in the coal stoker subcategory), submitted in response to the EPA Boiler MACT Combustion Survey of September 2008.] A&B therefore believes that it is unreasonable to expect that CO emissions of 50 ppm can be reliably achieved by either suspension burners, stoker boilers, or fuel cells firing biomass fuel, particularly a biomass fuel such as bagasse which has such a high, and highly variable, moisture content. EPA has as much as acknowledged that this level of emissions is not achievable by even the best performing boilers of these types when firing biomass, since it has proposed a CO emissions limit for new suspension burners designed to burn biomass as high as 1,010 ppm. A&B is unaware of any available control technology with the capability of reducing emissions from its biomass-fired boilers from their current levels to the level proposed for the coal stoker subcategory. Yet both new and existing combination boilers would be required to meet this limit when firing biomass or would be unable to continue operating.

Response: Please refer to the preamble for discussion of combination fuel units.

Commenter Name: Thomas Bakk
Commenter Affiliation: State of Minnesota Senate
Document Control Number: EPA-HQ-OAR-2002-0058-2950
Comment Excerpt Number: 4

Comment: Minnesota and national energy policy strongly encourages the use of biomass to provide energy and heat for industrial production. The forest products industry is a leader in energy generation from biomass. Unfortunately, the proposed rule will penalize boilers that co-fire coal and biomass. Because these "combination" boilers have different emission profiles from boilers that burn only coal or biomass, they don’t fit into either the coal-fired subcategory or the biomass subcategory. We believe that EPA should include combination boilers burning more than 10% coal in the coal subcategory for the purpose of setting emission standards for particulate/metals, mercury and acid gases and the biomass subcategory for emissions of carbon monoxide and dioxins/furans.

Response: Please refer to the preamble for discussion of combination fuel units.

Commenter Name: Sean M. O'Keefe
Commenter Affiliation: Alexander and Baldwin, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-3196
Comment Excerpt Number: 5

Comment: On the basis of CO emissions alone, there is clearly an urgent need to revise the proposed boiler subcategories so that emissions limits for combination boilers firing biomass fuels will be correctly established based on the best-performing similar units rather than on the best-performing coal-fired units. [It is A&B's understanding that of the units forming the basis for the MACT Floor for CO emissions from coal stoker boilers, only one — Puunene Boiler 3 — fires any biomass fuel.] One option for addressing this issue would be to simply revise the proposed definitions of "unit designed to burn biomass subcategory" and "unit designed to burn coal subcategory" so that units which burn significant quantities of biomass, and certainly units which burn primarily (i.e., more than 50 percent) biomass, would be placed in the biomass rather than in the coal subcategory. While this approach is not without its limitations — it would not necessarily address concerns regarding emissions of fuel-based HAPs (see further discussion below) - it would at least address the inappropriately low, and likely unachievable, proposed limits on CO emissions from combination boilers firing biomass fuels.

An alternative approach to addressing combination boilers would be to recognize that they do not fit cleanly into either the coal-fired or biomass-fired boiler subcategory. That is, while it makes sense to regulate combination boilers as biomass-fired boilers with regard to combustion-based HAPs (CO and dioxins/furans), when firing coal they may be unable to meet limits on fuel-related HAPs under the biomass subcategory due to the lower levels of metals, halogens, and mercury typically found in biomass fuels. Thus, it may make more sense to subject combination boilers to the same emission standards for PM/metals, mercury, and acid gases as the coal subcategory while applying the biomass subcategory emissions limitations for CO and dioxins/furans. A&B strongly endorses this approach. However, in the event that this broader approach proves to be infeasible we believe it is critically important for EPA to ensure that appropriate CO emissions standards are applied to combination boilers which fire significant quantities of biomass by assigning these boilers to the biomass subcategory.

Response: Please refer to the preamble for discussion of combination fuel units.

Commenter Name: Leslie Sue Ritts
Commenter Affiliation: National Environmental Development Association's Clean Air Project NEDA/CAP
Document Control Number: EPA-HQ-OAR-2002-0058-2794.1
Comment Excerpt Number: 6

Comment: Because EPA has overlooked or ignored the combustion chemistry interactions between some pollutants, the proposed standards are arbitrary and unreasonable.

Because EPA analyzed testing performed by industry across a large sample of industrial boilers but segregated the results by pollutant in establishing the MACT floors, it appears that very few sources (including those identified as best performers for certain HAPs) can meet the proposed standards. EPA appears to have overlooked the combustion chemistry interactions between some pollutants, such as PM and CO with mercury and hydrogen chloride. In addition, EPA has seemingly ignored the fact that most multi-fuel boilers burn a variety of fuels over the year depending on costs, availability, transportation costs, etc., because the proposed MACT standards are based on control equipment that can be optimized for one HAP or fuel, but the simultaneous effect for other HAPs, other fuels or on other control equipment performance is either unknown or incompatible. We submit that this topic should be evaluated for each proposed MACT emission limit when the set of boilers at issue use multiple fuels or that EPA must explain why such criteria are not inherent in the statutory term “achievable.”

Response: See the preamble for response to the pollutant-by-pollutant approach and achievability of standards as well as response to how the subcategories and thresholds were adjusted in the final rule to better accommodate combination fuel boilers.

Commenter Name: Christy Sammon
Commenter Affiliation: Southeast Lumber Manufacturers Association
Document Control Number: EPA-HQ-OAR-2002-0058-2727.1
Comment Excerpt Number: 6

Comment: Multi-fuel boilers should be addressed as appropriate subcategories as needed.

Response: Please refer to the preamble for discussion of combination fuel units.

Commenter Name: David Bonistall
Commenter Affiliation: NewPage Corp
Document Control Number: EPA-HQ-OAR-2002-0058-2920.1
Comment Excerpt Number: 9

Comment: NewPage has a number of boilers that are designed to simultaneous co-fire coal in an amount greater than 10% on a heat input basis and with greater than 10% biomass. These units are designed with coal and biomass as primary fuels. According to the boiler design descriptions and performance information, these units can simultaneously burn significant amounts of coal and/or biomass where up to 70% of the heat input could be supplied by either of these primary fuels.

These "combination boilers" that co-fire coal and biomass have different emission profiles than units that burn coal or units that burn biomass. As a result, combination boilers do not fit cleanly into either the coal-fired boiler subcategory or the biomass-fired boiler subcategory. To better accommodate the actual performance of combination boilers, we recommend that EPA adjust the proposed subcategories so combination boilers belong to the coal subcategory for purposes of regulating the fuel-based HAP (i.e., metals/PM, HAP acid gases, and mercury) and the biomass subcategory for purposes of regulating the combustion-based HAP (i.e., CO (as a surrogate for organic HAPs) and dioxins/furans). Although an alternate approach would be for EPA to create a separate combination boiler sub-category. NewPage does not support this approach as the amount of data in the database to determine the combination boiler subcategory floors would be much more limited than our proposed approach.

Response: Please refer to the preamble for discussion of combination fuel units.

Commenter Name: Holly R. Hart
Commenter Affiliation: United Steelworkers Union
Document Control Number: EPA-HQ-OAR-2002-0058-2964.1
Comment Excerpt Number: 9

Comment: In many industries there is a push to include biomass in the fuel mix of boilers that rely primarily on fossil fuel. However, for example, EPA proposes to define a boiler that burns at least 10% coal as subject to the MACT for coal-fired boilers. The proposal to define and regulate any boiler using less than 10% coal and more than 10% biomass as a pure biomass boiler is similar. Both these proposed definitions have the potential to create a significant disincentive to the development and use of mixed fuel boilers and operation schemes, and could serve to limit the future development of biomass fuels.

USW therefore urges EPA to consider a separate subcategory for true mixed-fuel boilers that will be sufficient to protect the public health, but will allow in particular the innovative development and use of biofuels as a viable economic option and clean energy job generator.

Response: Please refer to the preamble for discussion of combination fuel units.

Commenter Name: David Bonistall
Commenter Affiliation: NewPage Corp
Document Control Number: EPA-HQ-OAR-2002-0058-2920.1
Comment Excerpt Number: 10

Comment: As the rule is currently proposed, boilers that burn more than 10% coal with biomass will be classified in the coal subcategory; however, these boilers will not be able to meet the coal subcategory carbon monoxide (CO) emission standard for organic HAPs due to the substantial amount of biomass that they burn. Biomass fuels are more variable than coal and typically contain significantly more moisture than coal. As a result, it is more difficult to control combustion conditions in combination boilers than in boilers combusting only coal, which means that CO emissions from combination boilers often will be unavoidably greater than from a comparable coal-fired boiler. This makes the coal subcategory an inappropriate choice for establishing standards for combustion-based HAP. Regulating combustion-based HAPs, in particular CO, from combination boilers under the biomass subcategory makes more sense because combination boilers will perform more like biomass-fired boilers with regard to the combustion related HAPs.

On the other hand, biomass typically has lower levels of metals, halogens, and mercury than coal. As a result, regulating the fuel-related HAPs from combination boilers under the biomass subcategory would be inappropriate because the amount of co-fired coal would in many cases prevent combination boilers from meeting the standards for fuel-based HAPs. For this reason, it makes more sense to regulate fuel-based HAP emissions from combination boilers under the coal subcategory.

Response: Please refer to the preamble for discussion of combination fuel units.

Commenter Name: Cathy S. Woollums
Commenter Affiliation: MidAmerican Energy Holdings Company
Document Control Number: EPA-HQ-OAR-2002-0058-2786.1
Comment Excerpt Number: 19

Comment: MidAmerican Requests Clarification on what limits apply to Dual-Fueled Units. In this proposed rule, the EPA suggests that new or existing boilers or process heaters which burn at least 10 percent coal, biomass, liquid fuel, or gaseous fuel would fall into the corresponding fuel subcategory. However, the EPA fails to account for dual fueled units that have the capability to utilize more than one fuel type over the 10 percent threshold level. For example, if a boiler has the capability to run on natural gas, coal, and/or biomass at any point in excess of 10%, with the fuel choice dictated by economics and availability, what fuel category would be applied under such a multi-fuel scenario? MidAmerican requests clarification from EPA regarding this issue.

Response: Please refer to the preamble for discussion of combination fuel units.

Commenter Name: Chris M. Hobson
Commenter Affiliation: Southern Company
Document Control Number: EPA-HQ-OAR-2002-0058-2741.1
Comment Excerpt Number: 39

Comment: EPA's method of assigning units to a particular fuel subcategory may be inappropriate for units that co-fire multiple fuel types. EPA attempted to map specific fuels to the generic list of fuel types (i.e. "sander dust" - "biomass", "pet-coke" - "coal"). For many fuels, this mapping strategy is straightforward. However, for units that co-fire multiple fuel types (i.e. "coal/biomass", "coal/natural gas") where a breakdown of the heat input from each fuel type was not provided during the emissions test, EPA appears to have assigned these units to the fuel type containing the highest overall HAPs concentration. For example, "coal/natural gas" was assigned to the "coal' subcategory. Since the relative heat input contribution during the test is unknown, there is no way to quantify the bias this might create in the emissions data pool for each fuel type. Unfortunately, this appears to be common for many of the reported emissions tests, particularly for biomass-fired units.

RMB notes that correctly assigning units based on fuel type may be an impossible task given that the necessary data was probably never provided. Sources may not have had the capability of measuring individual fuel flows and/or EPA's spreadsheet templates may not have had the specific fuel type listed for one or more of the fuels combusted during the test.

Response: Please refer to the preamble for discussion of combination fuel units.

Commenter Name: Chris M. Hobson
Commenter Affiliation: Southern Company
Document Control Number: EPA-HQ-OAR-2002-0058-2741.1
Comment Excerpt Number: 48

Comment: A significant number of units in the coal-, biomass-, and liquid subcategories (HCl, PM, Hg, CO, and D/F-TEQ) were co-firing gas during the ICR emissions test. Average heat input from gas firing (either 'Gas 1' or 'Gas 2') ranged from 2% - 90% of total heat input although in most cases co-firing was less than 10%. Gas co-firing introduces a bias in the emissions for non-gas subcategories because emissions are averaged with a lower HAP-containing fuel. This bias can be significant depending on the gas firing rate and relative difference in pollutant concentration. For instance, the bias in PM emissions due to 15% natural gas co-firing for a biomass-fired unit that has typically has PM emissions of 0.02 lb/mmBtu during biomass (only) combustion is approximately 15%. RMB recommends that EPA either exclude all test runs where a unit was co-firing gas or adjust the data accordingly to remove the gas-firing bias. This would result in an emissions pool for each subcategory where the emissions are based on the equivalent of 100% combustion of the fuel type for that subcategory. A complete list of test runs containing gas co-firing can be found in Attachment C.

Response: Please refer to the preamble for discussion of combination fuel units.

Commenter Name: Christopher S. Colman
Commenter Affiliation: Hovensa LLC
Document Control Number: EPA-HQ-OAR-2002-0058-2863.1
Comment Excerpt Number: 29

Comment: 5.EPA Incorrectly Assumes that a Heater or Boiler is Designed Around a Single Fuel

Because island/remote refining or loading facilities do not have access to natural gas, they must supplement their fuel gas with oil. The amount of gas available can vary substantially, as noted above. For example, during a turnaround of an FCC unit that makes substantial amounts of fuel gas, heaters and boilers that typically burn almost all fuel gas must be able to burn almost entirely fuel oil to remain in operation. As a consequence, heaters and boilers on island facilities like HOVENSA must be designed to be able to burn far more than 10% gas or oil. These units are designed to be dual fuel units, able to provide the heat inputs needed on both fuels. (see submittal picture of a standard John Zink combination burner design, with an oil gun in the center surrounded by gas burners.)

EPA, in establishing its subcategories, did so on the incorrect assumption that a unit is designed for one type or fuel or another, and set a maximum 10% threshold for the alternate fuel:

Response: Please refer to the preamble for discussion of combination fuel units. See preamble for discussion of the new non-continental subcategory.

Commenter Name: Kirby D. Juntila
Commenter Affiliation: Marquette Board of Light and Power
Document Control Number: EPA-HQ-OAR-2002-0058-3175
Comment Excerpt Number: 1

Comment: The Marquette Board of Light and Power submitted a plan to the State of Michigan to achieve the targets by fuel switching to biomass in the coal fired stoker boiler. The low ash content of the wood-based biomass material may require that a blend with coal will be necessary. While our intent is to minimize the amount of coal used in the fuel blend by maximizing the amount of biomass combusted, it may require that more than 10% of the blend be made up of coal. This means that the carbon monoxide emission limit would be 50 ppm when combusting the biomass/coal blend if the 2010 boiler MACT goes into effect. Based on our experience with trying to combust biomass, the new limit will force us to abandon this project and continue burning coal as the only fuel in this unit.

Response: Please refer to the preamble for discussion of combination fuel units.

Commenter Name: Richard Rosvold
Commenter Affiliation: Xcel Energy Services, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2955.1
Comment Excerpt Number: 2

Comment: Xcel Energy owns and operates boilers that burn coal and biomass in the same boiler, but not concurrently. The data acquisition and handling system component of the continuous emissions monitoring system (GEMS) on these units tracks the F-factor associated with the fuel being combusted on a minute basis, making it easy to distinguish when a particular fuel is being combusted. For these units, it makes sense for the carbon monoxide (CO) limits to be based on the fuel being burned at the time, not by arbitrarily placing these units in one category or the other. In fact, it would be fairly straightforward for these units to comply with different CO limits based on the fuel being burned at the time. Having over thirty years of experience burning these fuels in these boilers, we are certain that the CO limit prescribed for coal-burning units cannot be achieved while burning biomass. We therefore request the EPA allow boilers burning a variety of fuels to comply with the emission limits for the specific fuel being burned if the emissions from that boiler are being monitored by CEMs.

Response: Please refer to the preamble for discussion of combination fuel units.

Commenter Name: Tim Hagley
Commenter Affiliation: Minnesota Power
Document Control Number: EPA-HQ-OAR-2002-0058-2829.1
Comment Excerpt Number: 2

Comment: The Proposed Rule Will Discourage or Prevent Co-Firing of Biomass by Applying Coal-Fired Unit Based CO Emission Limits that are Unachievable while Cofiring with Biomass. Minnesota Power is aggressively expanding the use of renewable, clean energy resources through new wind projects, and maximizing our biomass and hydro resources, consistent with national energy and climate policy and Minnesota renewable energy standards. We have two facilities that co-fire biomass with coal to produce energy, and we continually look for ways to maximize our use of biomass. One facility, REC, has two solid fuel boilers co-firing biomass that meet the definition of industrial boilers, and would be impacted by this rule.

The rule requires those sources that co-fire biomass with coal, to apply the coal fired emission limits if coal comprises more than 10 percent of the fuel mix. On average, REC burns a blend of 70% biomass (primarily wood chips) and 30% coal in the stoker fired boilers, however on an hourly basis, the blend may vary. The proposed coal-based emission limit for CO is roughly an order of magnitude more stringent than the biomass limit for a stoker-fired boiler (50 ppm vs. 560 ppm), and is not achievable with our existing boilers while co-firing with biomass. A preliminary analysis makes it clear that, even with expensive modifications to the boilers, the coal-based emission limit for CO may still be unattainable. Biomass fuels are more variable in size and moisture content than coal, making it more difficult to control combustion conditions, contributing to higher CO emissions, which explains the higher CO emission limit for stoker-fired biomass boilers.

Response: Please refer to the preamble for discussion of combination fuel units.

Commenter Name: Gary Chandler
Commenter Affiliation: Association of Washington Business
Document Control Number: EPA-HQ-OAR-2002-0058-2914.1
Comment Excerpt Number: 4

Comment: Adjusting the proposed subcategories to correctly accommodate the unique characteristics of combination boilers, which simultaneously burn coal and biomass. These combination boilers have different emission profiles and do not fit into either the coal-fired boiler subcategory or the biomass-fired boiler subcategory.

Response: Please refer to the preamble for discussion of combination fuel units.

Commenter Name: Jim Weeks
Commenter Affiliation: Michigan Municipal Electric Association
Document Control Number: EPA-HQ-OAR-2002-0058-2795.1
Comment Excerpt Number: 5

Comment: For Marquette Shiras Unit 2 and other existing electricity boilers that are striving to move toward a cleaner, more diversified fuel supply using biomass fuels, EPA should amend the subcategory for combination coal-biomass boilers to promote the use of renewable biomass fuel, and to address the severe difficulties that certain combination units will have meeting the proposed technology-based standards.

Marquette is planning on meeting the state renewable portfolio standards by blending a mixture of wood biomass (Reriewfuel) with bituminous coal (the exact ratio has yet to be determined). However, in a unit such as IvIarquettels Shims Unit 2 that may be burning up to a 50/50 blend of biomass and coal, it will be extremely difficult if not impossible to meet the coal sub-category's CO emission standard for organic HAPs. Yet, a blended/combination boiler cannot be simply subject to the proposed biomass subcategory limitations either, because a blended combustion may result in higher PM, metals, mercury and acid gases.

EPA's rule, as proposed, would likely require Marquette to reduce biomass fuel stocks drastically and return to primarily coal combustion at Unit 2. This is a perverse policy incentive given the greenhouse gas reductions possible from biomass use. in addition, Marquette and the State of Michigan are counting on projects like the Shiras Renewafuel project to catalyze and support the biomass industry in critical areas of the state where biomass supply is not yet certain. Likewise, Marquette is counting on the Shiras biomass generation to allow the system to meet the Renewable Energy Standard (portfolio standard) created by Michigan Act 295, the "Clean, Renewable and Efficient Energy Act of 2008." Again, under EPA's proposed categorization of a unit such as Shiras 2 as a coal sub-category unit that must meet CO limits that are likely unachievable for combination units with significant biomass capacity, Marquette may have to abandon or significantly reduce this renewable resource.

A blended-fuel, combination boiler needs a "blended" set of emissions limitations to reflect the technical and policy factors at combination boilers. For these reasons, MMEA and Marquette ask EPA to review the way that biomass-coal combination boilers will be regulated under the MACT. Boilers burning more than 10 percent coal with biomass should be subject to the same emission standards for PM/metals, mercury and acid gases as the coal snbcategory, but also be subject to the biomass sub-category limitations for CO and dioxins/rums.

Response: Please refer to the preamble for discussion of combination fuel units.

Commenter Name: Jennifer Klein
Commenter Affiliation: Ohio Chamber of Commerce
Document Control Number: EPA-HQ-OAR-2002-0058-2901.1

Comment Excerpt Number: 6

Comment: Within certain industry sectors, boilers are commonly used that co-fire coal in an amount greater than 10 percent heat input basis with at least 10 percent biomass. These "combination boilers" that simultaneously burn coal and biomass have different emission profiles than units that burn only coal or units that burn only biomass. As a result, combination boilers do not fit cleanly into either the coal-fired boiler subcategory or the biomass-fired boiler subcategory. To better accommodate the actual performance of combination boilers, EPA should adjust the proposed subcategory for combination boilers so that they belong to the coal subcategory for purposes of regulating the fuel-based HAP and the biomass subcategory for purposes of regulating the combustion-based HAP.

Response: Please refer to the preamble for discussion of combination fuel units.

Commenter Name: Tom Midyett
Commenter Affiliation: Tennessee Paper Council
Document Control Number: EPA-HQ-OAR-2002-0058-2691.1
Comment Excerpt Number: 7

Comment: As the rule is currently proposed, boilers that burn more than 10 percent coal with biomass will be classified in the coal subcategory; however, most such boilers will not be able to meet the coal subcategory CO emission standard for organic HAPs due to the substantial amount of biomass that they burn. Biomass fuels are more variable than coal and typically contain significantly more moisture than coal. As a result, it is more difficult to control combustion conditions in combination boilers than in boilers combusting only coal, which means that CO emissions from combination boilers often will be unavoidably greater than from a comparable coal-fired boiler. This makes the coal subcategory an inappropriate choice for establishing standards for combustion-based HAP. Regulating combustion-based HAP from combination boilers under the biomass subcategory is more appropriate because combination boilers will perform more like biomass-fired boilers with regard to the combustion related HAPs.

On the other hand, biomass typically has lower levels of metals, halogens, and mercury than coal. As a result, regulating the fuel-related HAPs from combination boilers under the biomass subcategory would be inappropriate because the amount of co-fired coal would in many cases prevent combination boilers from meeting the standards for fuel-based HAPs. For this reason, it is more appropriate to regulate fuel-based HAP emissions from combination boilers under the coal subcategory.

Notably, if owners or operators of combination boilers anticipate difficulty complying with the proposed CO standard, they may have to switch away from biomass and burn more coal to be able to comply with the coal subcategory emission standards. This unintended consequence is in direct contravention of national and local environmental and climate policy encouraging the use of renewable biomass fuels.

Response: Please refer to the preamble for discussion of combination fuel units.

Commenter Name: Ted Sturdevant
Commenter Affiliation: Washington Department of Ecology
Document Control Number: EPA-HQ-OAR-2002-0058-2987.1
Comment Excerpt Number: 7

Comment: EPA should recognize that boilers may utilize multiple fuels when setting emission limitations. In other NSPS and NESHAP-MACT standards, EPA has established a formula that considers the full mix of fuels used. Such a formula could be applied in this rule to recognize the emissions from each type of fuel rather than assuming that one fuel dictates the emission limitations.

Response: Please refer to the preamble for discussion of combination fuel units.

Commenter Name: Mark W. Kowlzan
Commenter Affiliation: Packaging Corp. of America
Document Control Number: EPA-HQ-OAR-2002-0058-2913.1
Comment Excerpt Number: 7

Comment: The Rule proposes five boiler subcategories based on the type of fuel cornbusted, namely, coal, biomass. liquid fuel, natural/refinery gas and other gas; coal and biomass subcategories are further subdivided by boiler types. Of PCA's thirteen power boilers, the rule classifies six as coal (stoker), two as biomass (stoker), two as liquid fuel, two as "other gas" and one as natural gas.

EPA has elected to include in the coal subcategory all units that use coal at a rate greater than 10 percent of the heat input. Three of our company's "coal" boilers combust coal, along with a host of other fuels such as woody biomass (bark, sawdust, fiber rejects), tire-derived fuel, old-corrugated container rejects and wastewater treatment plant residuals. This practice serves three rational purposes, a) it takes advantage of those materials that are produced on-site and have fuel value, b) it reduces the amount of material that might otherwise go to landfills, and c) it offsets the use of purchased fossil fuels. By failing to recognize the wide diversity of fuel inputs, the variation in availability of these fuels and the inherent variation in fuel quality (i.e., BTU and moisture content) and related impact on source emissions, EPA effectively penalizes facilities that maximize the use of these fuel streams by applying a "one size fits all" approach to emission limits in the context of a very restricted number of subcategories. It will have the unintended consequence of forcing some facilities to burn more coal in efforts to meet compliance with this rule.

We recommend that the Agency rework the source subcategories to include boilers that combust a combination of solidfuels and establish emission limits reflective of the variation in fuels andfuel quality.

Response: Please refer to the preamble for discussion of combination fuel units.

Commenter Name: Kirby D. Juntila
Commenter Affiliation: Marquette Board of Light and Power
Document Control Number: EPA-HQ-OAR-2002-0058-3175
Comment Excerpt Number: 8

Comment: The EPA needs to consider a co-firing subcategory for coal and biomass. A boiler burning a 50% coal/50% biomass blend will not meet the 50 ppm CO limit. Essentially, this rule provides no incentive to burn biomass unless a boiler can operate on biomass alone. Burning biomass alone may not be feasible in existing coal-fired stoker units due to the low ash content of the biomass and the inability to form an ash bed on the traveling grates. The EPA needs to consider adding a category that offers an incentive to offset the combustion of coal with biomass meeting limits somewhere between the stokers designed to burn coal and the stokers designed to burn biomass. This needs to be taken into consideration so that the EPA does not implement a rule that would conflict with the Renewable Portfolio Standards being adopted by many proactive states in an effort to move away from electricity generated from the combustion of coal.

Response: Please refer to the preamble for discussion of combination fuel units.

Commenter Name: Mark W. Kowlzan
Commenter Affiliation: Packaging Corp. of America
Document Control Number: EPA-HQ-OAR-2002-0058-2913.1
Comment Excerpt Number: 8

Comment: Within PCA three of our thirteen boilers co-fire coal in an amount greater than 10% heat input basis along with at least 10% biomass. These "combination boilers" have different emission profiles than units that burn exclusively coal or exclusively biomass. In all cases, coal constitutes a minority fuel in these combination boilers. The units perform more like coal boilers with respect to fuel-based emissions (e.g .. PM, HCI and Hg) and perform more like biomass boilers with respect to combustion-based emissions (e.g., CO and DIF).

It is important that EPA recognize that by placing combination boilers burning substantial amounts of biomass in the coal subcategory the boilers will be unable to meet the CO emission standard based on coal firing due to the variable moisture content of biomass and its impact on combustion conditions. Similarly, biomass typically has lower levels of metals, halogens, and Hg than coal. Placing combination boilers in the biomass subcategory is inappropriate due (0 the influence that coal exerts on the fuel quality / emissions characteristics due to coal's higher levels of metals, halogens and Hg, Therefore, it makes more sense to regulate fuel-based HAP emissions from combination boilers under the coal subcategory.

Given these realities, EPA should revise the way combination boilers are regulated under the proposed Boiler MACT. Specifically, combination boiler emission standards should be bifurcated. Combination boilers burning more than 10% coal with biomass should be subject to the coal subcategory PM/metals, Hg, and acid standards and should be subject to the biomass subcategory standards (if any) for co and dioxinsljurans.

Response: Please refer to the preamble for discussion of combination fuel units.

Commenter Name: David M. Kiser
Commenter Affiliation: International Paper Company
Document Control Number: EPA-HQ-OAR-2002-0058-2777.1
Comment Excerpt Number: 9

Comment: The data submitted shows that coal fired boilers that co-fire other fuels such as biomass will have a CO profile more akin to a biomass unit. Therefore, coal/biomass boilers will not be able to meet the proposed CO limits of 50 ppm (stokers designed to burn coal). The proposed limit of 560 ppm (stokers designed to burn biomass) is a more appropriate limit as demonstrated by the data in Attachment 4. Therefore any boiler firing more than 10% biomass should be subject to the appropriate biomass limit for CO regardless of what other fuels it fires.

Response: Please refer to the preamble for discussion of combination fuel units.

Commenter Name: Steven G. Hanson
Commenter Affiliation: Graphic Packaging International
Document Control Number: EPA-HQ-OAR-2002-0058-2723.1
Comment Excerpt Number: 9

Comment: GPI — Macon Mill operates a multi-fuel boiler that primarily combusts biomass (as defined by the proposed rule) and is also capable of combusting coal, fuel oil, and natural gas, historically at annual heat input capacities less than 10%. However, the boiler does have the potential to combust coal in excess of 10% heat input capacity on a short-term basis and, theoretically, even on an annual capacity basis. [From an operations perspective, there is a higher incentive to combust biomass than coal given fuel costs.] For example, in reviewing hourly fuel usage data on this unit, GPI — Macon Mill has operated the unit in the past two years at greater than 10% coal (heat input basis) for approximately 8% of the total hours of operation, with isolated hourly spikes around 90% of the heat input at that time. Accordingly, GPI — Macon Mill has the following concerns that arise based on the subcategory definition as proposed:

1. Is EPA intending that enforceable permit conditions be established limiting a multi-fuel boiler as described to less than 10% annual heat input capacity from coal?

2. If EPA is intending to establish enforceable conditions, would this limit be tracked on a calendar-year basis or 12-month rolling total basis? Any time-frame shorter than this would impede on flexibility needs for operation of a multi-fuel boiler (i.e., addressing fuel availability, fuel quality).

3. If a unit that historically operated at less than 10% annual heat input capacity from coal were to exceed the 10% basis in one year, would the classification of the unit change from designed to combust biomass to designed to combust coal? If yes, how would this be handled from a permitting and compliance perspective?
4. In general, GPI - Macon Mill feels that EPA needs to more specifically address the "enforceability" of the "designed to burn" classification and more clearly consider the implications of the multi-fuel boiler operation on testing considerations.

Response: Please refer to the preamble for discussion of combination fuel units.

Commenter Name: David O'Keefe
Commenter Affiliation: USEC, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-3122
Comment Excerpt Number: 12

Comment: Unit categorization clarifications. These categories do not fit actual operating units. Although a particular unit may have a primary fuel associated with it, they may also be able to operate without restrictions on the secondary fuel. Choice of fuel may simply be an economic decision. The rule should allow these choices. For example, what category is a unit that burns 50 percent coal and 50 percent liquid fuel or a unit that burns 50 percent liquid fuel and 50 percent natural gas? The proposal lists the Gas 1 subcategory as burning at least 90 percent natural gas. What happens if during one year a unit burns 90 percent natural gas and 10 percent liquid fuels, but the next year burns 90 percent liquid fuels and 10 percent natural gas? Do the applicable requirements, including performance testing, etc., change from year to year? Are the performance tests required only for the primary fuel? What happens if in the middle of the year a unit goes from having burned only one type of fuel to only another type the rest of the year — is this action precluded until an "annual" performance test can be conducted on the second fuel? These questions raised by actual use of operating units should be addressed.

Response: Please refer to the preamble for discussion of combination fuel units. See final rule and preamble for discussion of how units are assigned to subcategories and provisions available to switch subcategories.

Commenter Name: Sheila C. Holman

Commenter Affiliation: North Carolina Department of Environment and Natural Resources
Document Control Number: EPA-HQ-OAR-2002-0058-2798.1
Comment Excerpt Number: 13

Comment: Achievement of the more stringent coal-firing CO and dioxin/furan (D/F) emission limits may not be feasible when co-firing coal with any appreciable quantity of biomass materials, such as wood chips or wood pellets, in a boiler or process heater. The proposed coal-firing CO and D/F emission limits, with no adjustment for co-firing with higher emitting biomass, would discourage, if not effectively prohibit, co-firing biomass with coal as a renewable energy alternative to fossil fuel combustion. This prohibition is in conflict with current energy, environmental, and economic programs and policies to encourage biomass combustion as an alternative to fossil fuel combustion to reduce greenhouse gas emissions and dependency on foreign oil. EPA should provide prorated emission limits for both CO and D/F from biomass and coal cofired units that would be based on the percentage of total heat input from each fuel fired.

Response: Please refer to the preamble for discussion of combination fuel units.

Commenter Name: Dell Majure
Commenter Affiliation: Kimberly Clark Corp.
Document Control Number: EPA-HQ-OAR-2002-0058-2779.1
Comment Excerpt Number: 13

Comment: Within certain industry sectors, boilers are commonly used that co-fire coal in an amount greater than 10% heat input basis with at least 10% biomass. These “combination boilers” that simultaneously burn coal and biomass have different emission profiles than units that burn coal or units that burn biomass. As a result, combination boilers do not fit cleanly into either the coal-fired boiler subcategory or the biomass-fired boiler subcategory. To better accommodate the actual performance of combination boilers, we recommend that EPA adjust the proposed subcategory for combination boilers so that they belong to the coal subcategory for purposes of regulating the fuel-based HAP (i.e., metals/PM, HAP acid gases, and Hg) and the biomass subcategory for purposes of regulating the combustion-based HAP (i.e., CO (as a surrogate for organic HAPs) and dioxins/furans).

As the rule is currently proposed, boilers that burn more than 10% coal with biomass will be classified in the coal subcategory. However, most boilers in this subcategory will not be able to meet the coal CO emission standard for organic HAPs due to the amount of biomass that they burn. Biomass fuels are more variable than coal and typically contain significantly more moisture than coal. As a result, it is more difficult to control combustion conditions in combination boilers than in boilers combusting only coal, which means that CO emissions from combination boilers often will be unavoidably greater than from a comparable coal-fired boiler. This makes the coal subcategory an inappropriate choice for establishing standards for combustion-based HAP. Regulating combustion-based HAP from combination boilers under the biomass subcategory makes more sense because combination boilers will perform more like biomass-fired boilers with regard to the combustion related HAPs.

Biomass typically has lower levels of metals, halogens, and mercury than coal. As a result, regulating the fuel-related HAPs from combination boilers under the biomass subcategory would be inappropriate because the amount of co-fired coal would in many cases prevent combination boilers from meeting the standards for fuel-based HAPs. For this reason, it makes more sense to regulate fuel-based HAP emissions from combination boilers under the coal subcategory.

Notably, if owners or operators of combination boilers anticipate difficulty complying with the proposed CO standard, they may have to switch away from biomass and burn more coal to be able to comply with the coal subcategory emission standards. This unintended consequence of replacing biomass with coal is contrary to national energy and climate policy, which encourages the use of more renewable biomass fuel.

For both technical and policy reasons, EPA should revise the way combination boilers are regulated under the proposed rule. Combination boilers burning more than 10% coal with biomass should be subject to the same emission standards for PM/metals, mercury, and acid gases as the coal subcategory and should be subject to the biomass subcategory emission limitations for CO and dioxins/furans.

Response: Please refer to the preamble for discussion of combination fuel units.

Commenter Name: Michael Hutcheson
Commenter Affiliation: Ameren Services
Document Control Number: EPA-HQ-OAR-2002-0058-2803.1
Comment Excerpt Number: 18

Comment: US EPA should also establish a separate category for dual or multiple fuel boilers. It is improper to base a PM or Hg standard on data from a boiler firing 89% NG and 10 % fuel oil to a boiler firing all fuel oil. Even though both sources may be uncontrolled and essentially achieve the same “emission reduction” one source by virtue of being dual fueled is labeled as “achieving the maximum degree of emission reduction achievable”.

Response: Please refer to the preamble for discussion of combination fuel units.

Commenter Name: Paul N. Cicio
Commenter Affiliation: Industrial Energy Consumers of America
Document Control Number: EPA-HQ-OAR-2002-0058-2752.1
Comment Excerpt Number: 19

Comment: Combination Boilers – Combination coal and biomass boilers should have a CO standard based on biomass emissions.

In establishing the proposed standards, EPA has failed to accurately consider boilers that simultaneously co-fire fuels.
IECA generally agrees with this approach for HAPs that are strongly correlated with the HAP content of the fuel. However, the impact of emissions for CO and likely dioxin are based on the physical firing characteristics. We agree with EPA's rationale that boilers should be subcategorized based on their fuel type and design? however, we do not agree that all boilers are designed to burn only one fuel type and that they will encounter operational problems if another fuel type is fired at more than 10 percent of heat input. Some boilers are specifically designed to burn a combination of fuels, and to burn them in varying quantities.
In its decision making process, EPA appears to have only considered the "primary" fuel type. IECA is aware of numerous boilers for which this is not the case. Within the pulp and paper sector alone, there are at least 35 boilers, based on the survey database developed by EPA, that co-fire coal in an amount greater than 10% heat input basis with at least 10% biomass. These combination boilers that simultaneously burn coal and biomass have different emission profiles than units that burn coal or units that burn biomass. Other combination boilers burn pulverized coal or petroleum coke along with biomass in a fluid bed combustor type of boiler. According to one vendor who designs and builds boilers for this and other industries, 84 % of the boilers are designed to fire combinations of fuels at any one time. In some cases, these boilers are not able to reach full load on any single fuel. From this information it would seem that EPA has incorrectly presumed that boilers are designed based on a primary fuel. Rather, boilers can be designed to fire a variety of fuels, encompassing various types of solid, liquid, and gaseous fuels. This practice provides the most flexibility to facilities and allows them to select fuel mix based on various factors that include cost, availability, season, weather, etc.

Response: Please refer to the preamble for discussion of combination fuel units.

Commenter Name: Richard L. Killion
Commenter Affiliation: Babcock and Wilcox Power Generation Group
Document Control Number: EPA-HQ-OAR-2002-0058-2722.1
Comment Excerpt Number: 19

Comment: B&W is concerned about using the EPA's proposed 10%, by heat input, to define the unit fuel type subcategories. The inherent differences in the regulated fuels can greatly impact the emissions for the fuel-related HAP's (Hg, HCI, and PM).

While we recognize the need to subcategorize by fuel type, B&W proposes that only data obtained while firing 100% of the affected fuel type be used in determination of the MACT floor limit. For example, for the biomass limit, data from the top performing units firing 100% biomass should define the biomass floor limits.

This concern is emphasized when one considers that the unit setting the Mercury limit for new units burning coal (University of Iowa - IA - EP7 Boiler 11) utilizes a data set that includes data from three different fuel blends (100% coal, 50% coal / 50% biomass, 25% coal / 75% biomass). The range of average Mercury readings for the different blends is 1.40E-081b/MBtu to 2.4E-

071b/MBtu. This clearly illustrates the importance of fuel composition and resulting mercury emissions, as there is an order of magnitude difference in emissions when firing the different blends.

Table 2 summarizes the best performing units that set proposed emission limits for new units that have significant dilution fuel blends. [See submittal for Table 2: Best performing units that reported data while firing significant dilution fuel blends.]

Response: Please refer to the preamble for discussion of combination fuel units.

Commenter Name: Paul N. Cicio
Commenter Affiliation: Industrial Energy Consumers of America
Document Control Number: EPA-HQ-OAR-2002-0058-2752.1
Comment Excerpt Number: 20

Comment: Believe that it is appropriate for EPA to continue its approach for fuel related surrogates such as HCl, PM, and mercury. It does make sense to continue to use a 10 % threshold in such situations. However, for units firing biomass in appreciable quantities it would be appropriate to establish subcategories with limits that are based on the biomass category for carbon monoxide. Combination boilers burning more than 10% coal with biomass should be subject to the same emission standards for PM/metals, mercury, and HCl as the coal subcategory since the emissions of these pollutants are fuel dependent and will be driven primarily by burning coal.

Response: See the preamble for how EPA modified the subcategories and the heat input thresholds associated with the subcategory definitions for fuel based HAP and combustion-based HAP.

Commenter Name: Robert Thornton
Commenter Affiliation: International District Energy Association
Document Control Number: EPA-HQ-OAR-2002-0058-2918.1
Comment Excerpt Number: 24

Comment: In addition to the concern expressed above regarding liquid fuel boilers, other subcategories should be adjusted to properly accommodate the unique characteristics of combination boilers (e.g. those burning coal and biomass, coal and gas or biomass and gas).

Some boilers co-fire coal in an amount greater than 10% heat input basis with at least 10% biomass. These combination boilers have emission profiles than units that burn coal or units that burn biomass and do not fit cleanly into either the coal-fired boiler subcategory or the biomass-fired boiler subcategory. To better accommodate the actual performance of combination boilers, we recommend that EPA adjust the proposed subcategory for combination boilers so that they belong to the coal subcategory for purposes of regulating the fuel-based HAP (i.e., metals/PM, HAP acid gases, and mercury) and the biomass subcategory for purposes of regulating the combustion-based HAP (i.e., CO (as a surrogate for organic HAPs) and dioxins/furans).

As the rule is currently proposed, boilers that burn more than 10% coal with biomass will be classified in the coal subcategory; however, most such boilers will not be able to meet the coal subcategory CO emission standard for organic HAPs due to the substantial amount of biomass that they burn. Biomass fuels are more variable than coal and typically contain significantly more moisture than coal. As a result, it is more difficult to control combustion conditions in combination boilers than in boilers combusting only coal, which means that CO emissions from combination boilers often will be unavoidably greater than from a comparable coal-fired boiler. This makes the coal subcategory an inappropriate choice for establishing standards for combustion-based HAP. Regulating combustion-based HAP from combination boilers under the biomass subcategory makes more sense because combination boilers will perform more like biomass-fired boilers with regard to the combustion related HAPs.

On the other hand, biomass typically has lower levels of metals, halogens, and mercury than coal. As a result, regulating the fuel-related HAPs from combination boilers under the biomass subcategory would be inappropriate because the amount of co-fired coal would in many cases prevent combination boilers from meeting the standards for fuel-based HAPs. For this reason, it makes more sense to regulate fuel-based HAP emissions from combination boilers under the coal subcategory.

Notably, if owners or operators of combination boilers anticipate difficulty complying with the proposed CO standard, they may have to switch away from biomass and burn more coal to be able to comply with the coal subcategory emission standards. This unintended consequence of replacing biomass with coal is contrary to national energy and climate policy, which encourages the use of more renewable biomass fuel.
Therefore, for both technical and policy reasons, EPA should revise the way combination boilers are regulated under the Industrial Boiler MACT. Combination boilers burning more than 10% coal with biomass should be subject to the same emission standards for PM/metals, mercury, and acid gases as the coal subcategory and should be subject to the biomass subcategory emission limitations for CO and dioxins/furans.

Response: Please refer to the preamble for discussion of combination fuel units.

Commenter Name: Traylor Champion
Commenter Affiliation: Georgia-Pacific LLC
Document Control Number: EPA-HQ-OAR-2002-0058-2745.1
Comment Excerpt Number: 27

Comment: Georgia-Pacific has six boilers that burn a combination of coal or petroleum coke with biomass as described below. [The submittal includes a table detailing the fuel and design of these boilers.]

All of these units, with the exception of the Big Island unit, burn more than 10% coal with the biomass and thus fall into the coal subcategory.

Boilers burning more than 5% biomass in combination with coal, liquid or gaseous fuels should be required to meet the emission levels for non-organic HAP for the coal subcategory and the organic HAP (carbon monoxide (CO) and dioxin/furan) emission limits for the biomass subcategory.

Response: Please refer to the preamble for discussion of combination fuel units.

Commenter Name: Traylor Champion
Commenter Affiliation: Georgia-Pacific LLC
Document Control Number: EPA-HQ-OAR-2002-0058-2745.1
Comment Excerpt Number: 28

Comment: The non-organic HAP parameters, HCl and mercury are primarily driven by levels of these constituents in the fuels and are typically higher in coal than in biomass. Therefore, the limit for combination boilers should, as EPA envisioned in the proposed rule, be set at the coal subcategory limits.
However, organic HAP, CO and dioxin/furan, in combination boilers are less dependant on fuel constituents and much more influenced by the characteristics of the biomass being burned.

Wet biomass fuels (e.g., bark or hog fuel) have more variation in fuel quality and as such do not burn as evenly as coal. This variability results in higher CO emissions than coal combustion. At all of the facilities listed above, the biomass for these boilers are bark from the woodyard operation and purchased bark and thus have a fairly high moisture content (45% –55%). This may be even higher during rain events since the fuels are all stored in outside piles.

[Footnote 5: Elsewhere in these comments, Georgia-Pacific urges EPA to establish a particulate matter-alternative total select metals limit (TSM). Should EPA ultimately adopt this recommendation, GP notes that non-organic total select metals limits for combination boilers should be set at the coal limit for TSM.]

Response: Please refer to the preamble for discussion of combination fuel units.

Commenter Name: Traylor Champion
Commenter Affiliation: Georgia-Pacific LLC
Document Control Number: EPA-HQ-OAR-2002-0058-2745.1
Comment Excerpt Number: 29

Comment: The amount of wood residues burned in these units varies during the day. During load swings, which are very common in these units, coal will be the first fuel to be varied with steam demand, thereby changing the ratio of coal to biomass. There may be fuel feed system problems forcing the operators to stop either fuel to the boiler. All these process swings will cause significant variation in the CO emission levels.

Response: Please refer to the preamble for discussion of combination fuel units.

Commenter Name: Traylor Champion
Commenter Affiliation: Georgia-Pacific LLC
Document Control Number: EPA-HQ-OAR-2002-0058-2745.1
Comment Excerpt Number: 30

Comment: Operational experience supports, that the design of the unit influences organic HAP emissions. Stokers, fluid bed boilers and suspension burners all have different CO and dioxin/furan emission profiles.

These boilers will not be able to reliably meet the proposed limits for CO and dioxin/furan from coal stoker, pulverized coal, and coal FBC boilers.

Response: Please refer to the preamble for discussion of combination fuel units. See the preamble for a discussion of how CO limits were modified.

Commenter Name: Christopher S. Colman
Commenter Affiliation: Hovensa LLC
Document Control Number: EPA-HQ-OAR-2002-0058-2863.1
Comment Excerpt Number: 30

Comment: In contrast, the combination oil/gas burner design used at HOVENSA and other facilities is specifically designed so that it can fire up to 100% oil OR gas or fire both in varying quantities on the same burner. They are a completely different design than EPA contemplated in setting its standards and cannot be fairly included in the same subcategory with other units. It is noteworthy that while they were not considered in development of the MACT standards, these combination oil/gas design burners are well known in the burner industry and referenced in standard literature. See, Combustion Handbook, Volume II, pages 33-42, which devotes an entire subchapter to “Combination Gas-Oil Burners.”
There are several aspects of the co-firing design that are significant from a combustion perspective. First, when a burner is operating on both gas and oil, the gas flame can “rob” the oil gun of oxygen and result in higher CO emissions. Second, the need to fire up to 100% of the fuel in a heater or boiler as either oil or gas means that the firebox design cannot be optimized to maximize combustion efficiency. As a general rule, a firebox is designed to be about 2/3rds of

the flame height of fuel being fired. However, this is not possible in a co-fired unit, because of the different heights and characteristics of oil and gas flames:

The result is that the heater/boiler firebox configuration for co-fired unit is a compromise which does not maximize combustion efficiency or NOx emissions because it cannot be designed to do so.

Response: Please refer to the preamble for discussion of combination fuel units.

Commenter Name: Alicia Oman
Commenter Affiliation: National Association of Manufacturers
Document Control Number: EPA-HQ-OAR-2002-0058-2845.1
Comment Excerpt Number: 44

Comment: Within certain industry sectors, boilers are commonly used that co-fire coal in an amount greater than 10% heat input basis with at least 10% biomass. These “combination boilers” that simultaneously burn coal and biomass have different emission profiles than units that burn coal or units that burn biomass. As a result, combination boilers do not fit cleanly into either the coal-fired boiler subcategory or the biomass-fired boiler subcategory. To better accommodate the actual performance of combination boilers, we recommend that EPA adjust the proposed subcategory for combination boilers so that they belong to the coal subcategory for purposes of regulating the fuel-based HAP (i.e., metals/PM, HAP acid gases, and mercury) and the biomass subcategory for purposes of regulating the combustion-based HAP (i.e., CO (as a surrogate for organic HAPs) and dioxins/furans).

As the rule is currently proposed, boilers that burn more than 10% coal with biomass will be classified in the coal subcategory; however, most such boilers will not be able to meet the coal subcategory CO emission standard for organic HAPs due to the substantial amount of biomass that they burn. Biomass fuels are more variable than coal and typically contain significantly more moisture than coal. As a result, it frequently is more difficult to control combustion conditions in combination boilers than in boilers combusting only coal, which means that CO emissions from combination boilers often will be unavoidably greater than from a comparable coal-fired boiler. This makes the coal subcategory an inappropriate choice for establishing standards for combustion-based HAP. Regulating combustion-based HAP from combination boilers under the biomass subcategory makes more sense because combination boilers will perform more like biomass-fired boilers with regard to the combustion related HAPs.

On the other hand, biomass typically has lower levels of metals, halogens, and mercury than coal. As a result, regulating the fuel-related HAPs from combination boilers under the biomass subcategory would be inappropriate because the amount of co-fired coal would in many cases prevent combination boilers from meeting the standards for fuel-based HAPs. For this reason, it makes more sense to regulate fuel-based HAP emissions from combination boilers under the coal subcategory. Notably, if owners or operators of combination boilers anticipate difficulty complying with the proposed CO standard, they may have to switch away from biomass and burn more coal to be able to comply with the coal subcategory emission standards. This unintended consequence of replacing biomass with coal is contrary to national energy and climate policy, which encourages the use of more renewable biomass fuel.

Response: Please refer to the preamble for discussion of combination fuel units.

Commenter Name: Sarah E. Amick
Commenter Affiliation: Rubber Manufacturers Association
Document Control Number: EPA-HQ-OAR-2002-0058-2941.1
Comment Excerpt Number: 3

Comment: Many boilers and process heaters are designed to burn multiple fuels. For units designed to burn either liquid or gas, the unit's design provides no basis for assigning the unit between two subcategories (Gas 1 and Liquid). We believe the only reasonable basis for assigning units into subcategories is what fuel they actually burn. RMA recommends using the past calendar year as the basis, with appropriate consideration of potential changes in subcategory.

Response: Please refer to the preamble for discussion of combination fuel units.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 221

Comment: Boilers Are Not Always Designed To Burn One Fuel . We agree in general with EPA's rationale that boilers should be subcategorized based on their fuel type and design; however, we do not agree that all boilers are designed to burn only one fuel type and that they will encounter operational problems if another fuel type is fired at more than 10 percent of heat input. Some boilers are specifically designed to burn a combination of fuels, and to burn them in varying quantities. According to one vendor who designs and builds boilers for various industries, 84% of the boilers are designed to fire combinations of fuels at any one time. In some cases, these boilers are not able to reach full load on any single fuel. From this information it would seem that EPA has incorrectly presumed that boilers are designed based on a primary fuel. Rather, boilers can be designed to fire a variety of fuels, encompassing various types of solid, liquid, and gaseous fuels. This practice provides the most flexibility to facilities and allows them to select fuel mix based on various factors that include cost, availability, season, weather, etc. The subcategories of boilers should not be based on the fuel a boiler or process heater is designed to burn, but rather the fuel the unit actually burns.

Response: Please refer to the preamble for discussion of combination fuel units.

Commenter Name: Wayne Brandt
Commenter Affiliation: Minnesota Forest Industries
Document Control Number: EPA-HQ-OAR-2002-0058-3220
Comment Excerpt Number: 4

Comment: The Unique Characteristics of Combination (Biomass) Boilers.
Minnesota and national energy policy strongly encourages the use of biomass to provide energy and heat for industrial production. The forest products industry is a leader in energy generation from biomass. Unfortunately, the proposed rule will penalize boilers that co-fire coal and biomass. Because these "combination" boilers have different emission profiles from boilers that burn only coal or biomass, they don't fit into either the coal-fired subcategory or the biomass subcategory. We believe that EPA should include combination boilers burning more than 10% coal in the coal subcategory for the purpose of setting emission standards for particulate/metals, mercury and acid gases and the biomass subcategory for emissions of carbon monoxide and dioxins/furans.

Response: Please refer to the preamble for discussion of combination fuel units.

Other - Rationale for Subcategories

Commenter Name: N/A
Commenter Affiliation: Sierra Club, Clean Air Task Force, Earthjustice, and Natural Resources Defense Council
Document Control Number: EPA-HQ-OAR-2002-0058-3187.1
Comment Excerpt Number: 1

Comment: EPA's rationale for what it asserts are fuel- and design-based subcategories for industrial boilers, demonstrates that these subcategories actually are chosen based on the emissions characteristics of the subcategories, not on "class, type, and size" of boilers. What EPA is saying in essence is that different fuels when combusted yield different emissions characteristics – and EPA is subcategorizing to accommodate those emissions characteristics. Similarly, the Agency states that because "differences between given types of units can lead to corresponding differences in the nature of emissions and the technical feasibility of applying emission control techniques," it is justified in distinguishing between unit designs in setting standards. EPA states this is true, particularly for further subcategorizing beyond fuel type for standard setting for organic HAP emissions, for which the Agency notes "different designs and combustion systems, while having a minor effect on fuel-related HAP emissions, have a much larger effect on organic HAP emissions." 75 Fed. Reg. 32,016-32,017. But, the nature of emissions is not an element describing "class, type, or size" of boilers. Subcategorizing based on sources' emissions characteristics instead aims at the eventual achievability of the MACT floor by as many sources in the industrial category as possible – rather than standard setting based on what is achieved in practice by the best performers in the category. See NRDC v. EPA, 489 F.3d 1364, 1372 (D.C. Cir. 2007)(holding that EPA lacks authority to designate a subcategory "that allows harmful emissions in a manner contrary to Congress's statutory scheme.").

Response: EPA did not form the basis of its subcategories on emissions characteristics. Although emissions will vary by fuel type, other technical considerations were considered in the development of the subcategories including boiler design and operating limitations. For example, many commenters provided examples where combustion equipment is designed to burn fuels with a certain moisture content and as a result EPA identified a new subcategory to accommodate units that burn fuels with a hybrid grate/suspension design. See final rule and preamble for discussion of how units are assigned to subcategories and provisions available to switch subcategories.

Commenter Name: N/A
Commenter Affiliation: Sierra Club, Clean Air Task Force, Earthjustice, and Natural Resources Defense Council
Document Control Number: EPA-HQ-OAR-2002-0058-3187.1
Comment Excerpt Number: 8

Comment: EPA's Subcategorization Scheme Creates Perverse Incentives to Fuel Switch to Avoid More Stringent MACT Standards.

By defining the subcategories it has, EPA sets up incentives for existing boiler owners and operators, during the 3 year period between promulgation of final standards and compliance, to tinker with fuel mix in order to fit into the subcategory requiring the least additional controls. While the purpose of MACT at the outset is meant to be for all sources to control to the level actually achieved by the best performers, , however that performance is achieved, see Cement Kiln Recycling Coalition v. EPA, 255 F.3d 855, 861 (D.C. Cir. 2001), EPA's subcategories seem designed instead to at best perpetuate the status quo.3 The fuel-switching likely to result from EPA's subcategories (leaving aside the natural gas subcategory for which work practice standards are proposed) is likely to gravitate towards avoidance of control costs, not towards meeting the emissions performance of the best performers in the industry. In summary, EPA's proposed subcategories circumvent the fundamental objective of section 112(d), which is that "all sources in a category [will] at least clean up their emissions to the level that their best performing peers have shown can be achieved." Sierra Club v. EPA, 353 F.3d 976, 980 (D.C. Cir. 2004). EPA's scheme will motivate change, certainly, but not emissions clean up to the level of the best performing relevant sources. Moreover, where the Agency knows that fuel switching is possible and yields the best performance across the industry, subcategorizing in such a way as to provide disincentives to that compliance option runs counter to the statute's goal that MACT floor standards truly reflect the best performers. See also 42 U.S.C. § 7412(d)(2)(requiring consideration of "process changes [and] substitution of materials").

Response: EPA has consolidated many of the limits in the solid fuel subcategory for fuel-based HAP to partially address these concerns. See the preamble for further discussion of how concerns with combination boilers were treated in the final rule.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 174

Comment: EPA should provide guidance for boilers that don't clearly fit in a subcategory
EPA has established subcategories for boilers based on only a few designs and fuel types. EPA should provide guidance to facilities with other boiler designs (such as combination stoker/pulverized coal boilers and cyclone boilers) or burning fuels not described in the rule on how to determine which set of emission limits they are required to meet or include a requirement for boilers that do not fit in a subcategory to submit a case-by-case MACT analysis under 112(g) or 112(j).

Response: Sometimes a combustion unit reported more than one type of combustor design in the Survey Database, and a hierarchy was used to classify that unit in one of the combustor design categories. For coal units, the hierarchy was pulverized coal units, followed by fluidized beds and then stokers. Other designs not classified as pulverized coal, stoker, or fluidized bed were included in the stoker design category.

For biomass units, the hierarchy was units selecting both a suspension and stoker/grate firing method (excluding dry biomass units who were not believed to actually have this design given the nature of the fuel), followed by fluidized bed, followed by stokers (including sloped grate), Dutch ovens and suspension burners, and then fuel cells. Other designs not classified as stoker, fluidized bed, fuel cell, or Dutch oven, suspension burner or hybrid grate/suspension, were included in the stoker category.

Because units that were not identified to fit within one of the established subcategories were included in the coal or biomass stoker subcategories (depending on the fuel mix for which the unit was designed), units that do not fit within one of the subcategories will fall into the stoker subcategories, as appropriate. This designation impacts only the combustion-based pollutants (CO and dioxin/furan), and for the fuel-based pollutants, units will fall in the solid, liquid, or gaseous fuel subcategories as defined in the rule.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 49

Comment: For gas- and liquid-fired boilers and process heaters, subcategory assignments are proposed to be made on a unit by unit basis. This places undo operational restrictions on petroleum refinery operations where there are often gas imbalances or supply limitations. This concern can be mitigated by allowing subcategory assignments to be made on a facility-wide basis.

This additional flexibility is needed to assure compliance without restricting production and would provide for the same overall reduction of emissions. For illustration purposes, a simple example can be used. For a refinery with 2 process heaters each with a firing capability of 100 MMBTU/hr and with liquid burning capabilities, the current provision restricts each unit to firing no more than 10 MMBTU/hr of liquids on an annual average basis for assignment to the Gas 1 subcategory. However, it may be more feasible to fire oil on only one unit in a given year. If the determination were made on a facility wide basis, then one of the units could fire 20 MMBTU/hr of liquid fuel and the other unit would be restricted to firing only gas. Allowing the assignment of boilers and process heaters to be made on a facility-wide basis results in a more cost-effective rule because it allows fuel use to be optimized and improves operating flexibility.

Recommendation: Revise the gas and liquid subcategory assignment procedures to be based on whether the total facility heat duty is met by firing more than 10% liquids on an annual basis.

Response: The gas 1 subcategory has been revised to only allow burning of fuels other than gas 1 during periodic testing or gas curtailment and supply emergencies. If the units at the example facility provided in this comment are firing liquid fuels under these discrete circumstances they will still qualify in the gas 1 subcategory. The 10 percent threshold is no longer part of the gas 1 definition. For all of the other compelling reasons commenters have suggested about the different designs of the units and requests for additional subcategories, EPA disagrees that it should subcategorize on a facility instead of unit level.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 86

Comment: EPA has established subcategories for boilers based on only a few designs. EPA should provide guidance to facilities with other boiler designs (such as combination stoker/pulverized coal boilers and cyclone boilers) on which set of emission limits they are required to meet.

or include a requirement for boilers that do not fit in a subcategory to submit a case-by-case MACT analysis under 112(g) or 112(j).

Response: See response to comment EPA-HQ-OAR-2002-0058-3213.1, excerpt 174 for guidance on subcategorization.

Work Practices

Tune-Up Requirements

Commenter Name: N/A
Commenter Affiliation: Citizen
Document Control Number: EPA-HQ-OAR-2002-0058-0838.1
Comment Excerpt Number: 1

Comment: Would a limited use Boiler (30 to 60 days per year) in the Gas 1 subcategory at a Major Source have to conduct an annual tune-up?

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2761.1, excerpt 4 for a response to tune-up frequency for limited use combustors.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute and National Petrochemical and Refiners Association
Document Control Number: EPA-HQ-OAR-2002-0058-0851.1
Comment Excerpt Number: 14

Comment: The large effort associated with managing unit outages and special operations to conduct the required tune-ups and performance tests has been ignored. In some cases, boilers and process units will have to be shutdown to allow burner inspections or to make repairs resulting from the inspections. In all cases, the annual tune-up or performance testing will require operating the boiler or process heater at specific high rate conditions and often with unusual feeds to meet the requirement for maximum HCl and Hg in the feed during performance tests. Significant engineering effort will be required to manage these special operations, particularly for process heaters which typically are not spared and thus the entire process will have to be run non-optimally.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2906.1, excerpt 5 for a response the request for work practices not emission limits.

Commenter Name: Michael L. Steele
Commenter Affiliation: CraftMaster Manufacturing, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-1907.1

Comment Excerpt Number: 7

Comment: The requirement for an annual tune-up seems excessive. Testing should be required no more frequency than every five (5) years.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2874.1, excerpt 6 for a response to tune-up frequency.

Commenter Name: Michael L. Steele
Commenter Affiliation: CraftMaster Manufacturing, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-1907.1
Comment Excerpt Number: 38

Comment: Annual tune-up of Gas fired units >10 MMBtu per hour §63.7535(10)
Provisions are needed for standby units that only operate a few hours per year. Annual tune-up is not justified unless the unit is operating enough hours per year to realize any savings.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2761.1, excerpt 4 for a response to tune-up frequency for limited use combustors.

Commenter Name: William C. Herz
Commenter Affiliation: The Fertilizer Institute
Document Control Number: EPA-HQ-OAR-2002-0058-1910.1
Comment Excerpt Number: 6

Comment: TFI is concerned about the feasibility of conducting annual tune-ups while operating the reformer. Burner adjustments or pulling burners while units or associated process equipment are operating may present worker and/or safety hazards.
TFI requests that EPA specify tune-up frequencies based upon standard industry practice regarding scheduled turn-arounds or a frequency consistent with state-specific boiler inspection requirements. Other less intrusive portions of the requirements (e.g., inspecting air-to-fuel ratio, adjusting flame patterns, other manufacturer requirements) could continue to be conducted on an annual basis.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-3213.1, excerpt 112 for a response to tune-up requirements.

Commenter Name: Lisa Beal
Commenter Affiliation: Interstate Natural Gas Association of America
Document Control Number: EPA-HQ-OAR-2002-0058-2756.1

Comment Excerpt Number: 3

Comment: Work practices should be more flexible to avoid impractical requirements, and CO measurement should not be required for small natural gas-fired boilers.

The proposed rule itemizes work practice requirements for Gas 1 units 10 MMBtu/hr or larger in §63.7540(a)(10)(i) – (vi). In addition, §63.7540(a)(11) references those requirements for boilers and heaters smaller than 10 MMBtu/hr. INGAA supports work practice standards for natural gas-fired units. However, additional flexibility and clarity is required to ensure that the work practices can be implemented. For example, “manufacturer recommendations” are cited in several cases, and those procedures may not be available for some existing units (e.g., older or smaller units), or operator experience may provide operating practices that are more concise and preferable to manufacturer recommendations. In addition, the many facilities include very small natural gas-fired boilers or heaters that are covered by the rule. CO measurement is not warranted for small natural gas-fired units and a “blue flame” provides adequate assurance of “good combustion”.

“Good combustion practice” standards should be appropriate for work practices. For example, this includes burner cleaning and tuning so that a clean, blue natural gas flame is evident. By requiring “manufacturer recommendations”, the practices are too limiting and additional flexibility should be provided. As needed, operator practices (in lieu of “manufacturer recommendations”) could be documented in a simple plan. In addition, flexibility should be provided for CO measurement. For example, costly reference method tests are not warranted for boiler tune ups and reasonable test procedures should be acceptable – especially since tuning measures changes in CO emissions before and after adjustments. Major source facilities often include small gas-fired heaters or boilers (e.g., for water heating), and the majority of “very small” boilers or heaters will be natural gas-fired. CO measurement is not warranted for these small gas-fired units, and a combustion tune-up that follows a subset of the steps in §63.7540(a)(10)(i) – (v) is adequate to ensure good combustion and low emissions. As noted in the text below, INGAA recommends excluding natural gas-fired (or “Gas 1”) units smaller than 10 MMBtu/hr from CO measurement. At a minimum, the rule should include a threshold of 1 MMBtu/hr for CO measurement of gas-fired boilers or heaters.

INGAA recommends the following revisions to sections (i) through (v), with proposed revisions provided here as strikethrough for deleted text and new text bold and underlined:

“(i) Inspect the burner, and clean or replace burner any components of the burner as necessary;

(ii) Inspect the flame pattern and make any adjustments to the burner necessary to optimize the flame pattern consistent with good combustion practices (e.g., a blue flame for natural gas) or the manufacturer’s specifications;

(iii) As appropriate, inspect Inspect the system controlling the air-to-fuel ratio, and ensure that it is correctly calibrated and functioning properly;

(iv) Minimize total emissions of CO emissions consistent with good combustion practices or the manufacturer's specifications. CO measurement is not required for natural gas-fired boilers or process heaters smaller than 10 million Btu per hour;

(v) Measure the concentration in the effluent stream of CO in parts per million, by volume, dry basis (ppmvd), before and after the adjustments are made. Acceptable methods include standardized test methods and procedures using a portable analyzer that follow reasonable calibration and operating practices. CO measurement is not required for natural gas-fired boilers or process heaters smaller than 10 million Btu per hour;

As an alternative to the recommended "CO measurement exclusion" text in §63.7540(a)(10)(iv) and (v), the exclusion could included in §63.7540(a)(11) as follows:

"(11) If your boiler or process heater has a heat input capacity of less than 10 million Btu per hour, you must conduct a tune-up of the boiler or process heater biennially to demonstrate continuous compliance as specified in paragraphs (a)(10)(i) through (a)(10)(vi) of this section. CO measurement in (iv) and (v) is not required for natural gas-fired boilers or heaters smaller than 10 million Btu per hour."

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2960.1, excerpt 70 for a response to the tune-up exemption for small capacity units. Refer to DCN EPA-HQ-OAR-2002-0058-2761.1, excerpt 5 for a response to flexibility with respect to manufacturer's specifications and tune-ups. Refer to DCN EPA-HQ-OAR-2002-0058-2786.1, excerpt 15 for a response to tune-up requirements. Refer to DCN EPA-HQ-OAR-2002-0058-3137.1, excerpt 36 for a response to handheld instruments.

Commenter Name: Renee Lesjak Bashel
Commenter Affiliation: Small Business Ombudsman and Small Business Environmental Assistance Programs
Document Control Number: EPA-HQ-OAR-2002-0058-2854.1
Comment Excerpt Number: 3

Comment: Recommendation: Instead of biennial tune-ups for units 10 MMBTU/hr or under, set a trigger based on hours of operation of the unit.

Many operations can have a boiler or process heaters that they do not use often. Requiring them to conduct a tune up at a set time period can be costly in relation to their use of the unit. Setting the trigger for requiring a tune up based on hours of operation, similar to changing your car's oil every 3,000 miles, would account for level of use. After an initial tune-up, have the following tune-up fall based on manufacturer's specifications or after 17,000 hours of operation or five (5) years, whichever comes first.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2761.1, excerpt 4 for a response to tune-up frequency for limited use combustors.

Commenter Name: Michael Palazzolo
Commenter Affiliation: Alcoa Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2967.1
Comment Excerpt Number: 4

Comment: Section 63.7540(a)(10)(ii) of the proposed rule would require the owner/operator to inspect the flame pattern and make adjustments... to optimize the flame pattern. Metal process furnaces have numerous burners, some of which cannot be seen to "inspect the flame pattern". EPA should revise 63.7540(a)(10)(ii) to be required only ", if possible" or ", as applicable".

Response: In order to avoid finalizing requirements that cannot practically be met, EPA has adjusted the language to indicate “as applicable” for many of the tune-up requirements.

Commenter Name: Paula A. Gant and Bob Beauregard
Commenter Affiliation: American Gas Association and American Public Gas Association
Document Control Number: EPA-HQ-OAR-2002-0058-2724.1
Comment Excerpt Number: 5

Comment: We request that EPA clarify that portable analyzers may be used to measure the concentration of CO in the effluent stream.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-3137.1, excerpt 36 for a response to handheld instruments.

Commenter Name: John M. Cullen
Commenter Affiliation: Masco Corp.
Document Control Number: EPA-HQ-OAR-2002-0058-2417.1
Comment Excerpt Number: 5

Comment: The proposed work practice requirement for natural gas-fired boilers and process heaters in §63.7540(a)(10)(vi)(C) would require a source to include in the on-site annual report the "type and amount of fuel used over the 12 months to the annual adjustment". In order to comply with this requirement, the facility would have to install individual gas meters on the unit. Most facilities do not presently have such meters on individual units, and installing them would be unnecessarily burdensome.
A boiler or process heater that has not operated in the previous year should be allowed to skip the annual tune-up requirements.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2711.1, excerpt 5 for a response to handheld instruments. Refer to DCN EPA-HQ-OAR-2002-0058-2761.1, excerpt 4 for a response to tune-up frequency for limited use combustors.

Commenter Name: Steven M. Maruszewski
Commenter Affiliation: The Pennsylvania State University
Document Control Number: EPA-HQ-OAR-2002-0058-2729.1
Comment Excerpt Number: 10

Comment: The annual boiler tune-up as specified in Table 3 and as per §63.7540 (10)(iv) requires the air-to-fuel ratio be adjusted to "minimize total emissions of CO consistent with the manufacturer's specifications." Inherit to the combustion process is that any change in CO emissions will cause an inverse effect on NOx emissions. Other regulations (NOx RACT) have already been developed and are enforced to minimize NOx emissions. Penn State's existing Title V permit states that the University shall "make adjustments necessary to minimize total emissions of NOX, and to the extent practicable minimize the emissions of CO". These ideas are in conflict.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2506.1, excerpt 13 for a response the consequences of minimizing CO.

Commenter Name: Lisa Beal
Commenter Affiliation: Interstate Natural Gas Association of America
Document Control Number: EPA-HQ-OAR-2002-0058-2756.1
Comment Excerpt Number: 13

Comment: EPA should clarify scheduling requirements and provide additional flexibility for annual and biennial tune-ups.

For work practice standards, schedule requirements for tune-ups are specified in §63.7515(e). Specifically, each annual tune-up must be conducted between 10 and 12 months after the previous tune-up. Similar timing for sources subject to biennial tune-ups is not addressed. EPA should revise §63.7515(e) to provide flexibility and address biennial tune-up timing.

In some cases, an operator may have cause to conduct a tune-up more frequently that required by the rule. INGAA believes that it is unnecessary and counter-productive for the rule to specify a minimum time of 10 months on the periodicity for annual tune-ups, as long as the maximum allowed interval is met. If a source, for whatever reason (e.g., scheduling conflicts) wants to conduct an annual tune-up sooner than 10 months after the most recent tune-up, that flexibility should be allowed. In addition, the section appears to inappropriately reference §63.7520 (which addresses stack test requirements) rather than §63.7540 for tune-up requirements. Accordingly, INGAA recommends revisions to §63.7515(e) to address this issue for both annual and biennial tune-ups, with proposed revisions provided here as strikethrough for deleted text and new text bold and underlined:

“(e) If you are required to meet an applicable work practice standard, you must conduct annual performance tune-ups according to §63.7540(a)(10) or (11)§ 63.7520. Each annual tune-up must be conducted between 10 and no later than 12 months after the previous tune-up. Each biennial tune-up must be conducted no later than 24 months after the previous tune-up.”

Response: Refer to DCN EPA-HQ-OAR-2002-0058-3213.1, excerpt 112 for a response to tune-up requirements.

Commenter Name: Britt S. Fleming
Commenter Affiliation: Auto Group
Document Control Number: EPA-HQ-OAR-2002-0058-2775.1
Comment Excerpt Number: 15

Comment: Proposed Work Practices for Natural Gas-Fired Boilers/Process Heaters Require Further Clarification and Revision.

Overall, the Auto Group supports EPA’s proposed work practice tune-up requirement for natural gas boilers and process heaters. In general, the proposed tune-up requirement incorporates several key references to the manufacturers’ specifications for the affected unit, which is an appropriate and reasonable approach for these types of standards. Manufacturers’ specifications provide specific guidelines for optimizing performance and efficiency of affected units. For example, any regulatory requirements that would impose a specific CO limit instead of referencing the manufacturers’ specifications could have the unintended effect of increasing NOx emissions from a particular unit thereby resulting in compliance problems with other regulatory requirements. Specifically, as is well known in engineering circles, there is an inverse relationship between NOx and CO emissions from combustion sources. In other words, if CO emissions decrease from a boiler, NOx emissions will increase. This could result in an exceedance of emission limits in state permits and other regulatory requirements. Moreover, a decrease in CO emissions can lead to a decrease in thermal efficiency as well, which will lead to an increase in fuel consumption by the unit and could have the counter effect of increasing HAP emissions from the unit. For these reasons, EPA’s proposal to rely on manufacturers’ specifications for the tune-up requirement is a technologically sound and reasonable approach.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2506.1, excerpt 13 for a response the consequences of minimizing CO.

Commenter Name: Myra C. Reece
Commenter Affiliation: South Carolina Department of Health and Environmental Control
Document Control Number: EPA-HQ-OAR-2002-0058-2525.1

Comment Excerpt Number: 16

Comment: Clarify If The Use Of Existing Boiler Inspection Programs Satisfy Tune-Up Requirements

In the preamble, the EPA states that it has obtained information on units that reported using good combustion practices as part of the information collection effort, and that the data obtained indicates that units typically conduct tune-ups per state regulations and permits (75 FR 32025). While states like South Carolina already have a periodic boiler inspection program in place (implemented and enforced by a separate state agency), it appears from our survey of various states that the focus of those state required inspections is predominantly safety oriented and not efficiency based. Consequently, air-to-fuel ratios, the minimization of CO emissions, and the measurement of CO in the effluent stream may not be a part of typical state's tune-up inspections. The EPA should provide clear guidance in the rule on whether the existing safety boiler inspection programs are adequate to satisfy the proposed tune-up requirements.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2506.1, excerpt 13 for a response the consequences of minimizing CO.

Commenter Name: Britt S. Fleming
Commenter Affiliation: Auto Group
Document Control Number: EPA-HQ-OAR-2002-0058-2775.1
Comment Excerpt Number: 16

Comment: Work Practice Requirements in § 63.7540(a)(10) Should Allow for Handheld Analyzers.

The requirement in proposed § 63.7540(a)(10)(v) to measure the CO concentration in the effluent stream before and after adjustments are made to the unit does not appear to allow for the use of handheld analyzers and should be revised to allow for such flexibility. Current industry practice is to perform a tune-up or combustion safety audit using a handheld analyzer, and boiler manufacturers do not recommend the use of EPA reference test methods when tuning a boiler. Requiring sources to perform a full blown EPA test method for purposes of measuring CO in the effluent stream is not appropriate as it would be costly, require more time to perform, and would not provide additional or more useful real time information/data.

Other state regulatory agencies have allowed sources to use portable analyzers for purposes of complying with regulatory limits for boilers and process heaters.
Specifically, the Bay Area Air Quality Management District (BAAQMD) Regulation 9, Rule 7: Nitrogen Oxides and Carbon Monoxide from Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters (Regulation 9-7) allows for the use of a portable analyzer and includes a portable analyzer protocol. Given that portable analyzers are recognized as reliable by state permitting authorities, the Auto Group recommends that EPA amend the language in § 63.7540(a)(10)(v) to include the following underlined text:

(v) Measure the concentration in the effluent stream of CO in parts per million, by volume, dry basis (ppmvd), before and after the adjustments are made using a handheld analyzer or similar device or other method;
Not only will this amendment provide greater flexibility, but it will also reduce the costs associated with the tune-up requirement. Tune-up costs can range from $2,500/boiler for a handheld analyzer versus $6,500-8,200/boiler for a full EPA test method. The additional cost of a full EPA test method is not justified given that handheld analyzers are just as effective in measuring CO emissions from natural gas-fired boilers and process heaters and have been recognized by state permitting authorities as appropriate tools for doing so.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-3137.1, excerpt 36 for a response to handheld instruments.

Commenter Name: Myra C. Reece
Commenter Affiliation: South Carolina Department of Health and Environmental Control
Document Control Number: EPA-HQ-OAR-2002-0058-2525.1
Comment Excerpt Number: 17

Comment: Specify Methodology To Measure CO Concentration For Tune-Up Requirement

If the EPA decides to retain the requirement that sources having to comply with tune-up requirements must measure CO concentration in the effluent stream and must maintain on-site and submit to the administrator, if requested, an annual report containing this and other tune-up information as specified in 63.7540(a)(10), the proposed rule should specify the methodology to be used in measuring CO concentration.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-3137.1, excerpt 36 for a response to handheld instruments.

Commenter Name: Britt S. Fleming
Commenter Affiliation: Auto Group
Document Control Number: EPA-HQ-OAR-2002-0058-2775.1
Comment Excerpt Number: 18

Comment: EPA Should Consider Raising the Capacity Threshold for Annual Tune-Ups.

The Auto Group supports EPA’s requirement of less frequent tune-ups for smaller boilers/process heaters in lieu of emissions limits. EPA uses a heat input capacity of 10 mmBtu/hr as the threshold for requiring owners and operators of natural gas-fired boilers and process heaters to perform an annual tune-up as opposed to a biennial tune-up. [Footnote: See 75 Fed. Reg. at 32,059 (proposed §§ 63.7540(a)(10) and (11)).] While EPA explains in the preamble that work practices are appropriate for smaller boilers and process heaters that have smaller stack diameters, the agency does not explain why a heat input capacity of 10 mmBtu or less is the appropriate cut-off for requiring biennial as opposed to annual tune-ups. The Auto Group suggests that EPA consider raising the heat input capacity threshold that triggers annual tune ups to those boilers/process heaters with a heat input capacity of greater than 100 mmBtu/hr. Larger boilers (i.e., those greater than 100 mmBtu/hr) can benefit from annual tune-ups due to a more noticeable reduction in fuel use. The reduced fuel use for these larger units also results in cost savings as well as lower HAP emissions and use of this threshold heating rate would be consistent with the industrial boiler NSPS. [Footnote: See 40 C.F.R. Part 60, Subparts Db and Dc. Subpart Db covers boilers with a heat input capacity greater than 100 mmBtu/hr and Subpart Dc covers boilers with a heat input capacity from 10 mmBtu/hr through 100 mmBtu/hr.] Boilers with a heat input capacity of less than 100 mmBtu will not benefit as much from such frequent tune-ups given that experience with these smaller boilers indicates that there is rarely a change in the boiler performance from tune-up to tune-up. For this reason, EPA also should consider establishing biennial tune-ups for boilers with a capacity of 30 through 100 mmBtu/hr and every five years for boilers sized 10 to 30 mmBtu.

Response: We have not adjusted the size threshold of the tune-up to 100 mmbtu/hr in the final rule. The commenter did not provide sufficient justification that measurement of emissions is impractical at units between 10 and 100 and therefore these intermediate-sized boilers do not qualify for a work practice under 112(h). See preamble for justification of the work practice standards retained in the final rule.

Commenter Name: Britt S. Fleming
Commenter Affiliation: Auto Group
Document Control Number: EPA-HQ-OAR-2002-0058-2775.1
Comment Excerpt Number: 20

Comment: EPA also should consider increasing the time between required tune-ups once it is demonstrated that several consecutive (e.g., annual) tune-ups have produced minimal improvements in boiler operation as identified by decreases in CO emissions. EPA has allowed a similar kind of compliance flexibility in other regulations. For example, in the NESHAP for Steel Pickling, Subpart CCC, EPA allows the permitting authority to approve an alternative schedule for performance testing that would allow testing less frequently than annually. [Footnote: See 40 C.F.R. § 63.1161.] In addition, in the NESHAP for Primary Lead Smelting, Subpart TTT, EPA allows for less frequent testing when facilities are able to demonstrate consistent compliance with the standards. [Footnote: See 40 C.F.R. § 63.1543.] The rule allows operators up to 24 months between compliance tests if the results of the three most recent compliance tests demonstrate compliance. [Footnote: See 40 C.F.R. § 63.1543 § 63.1543(e).] EPA also allows this kind of compliance flexibility in other programs. For example, in Subpart BB of the RCRA Regulations applicable to valves in gas/vapor service, EPA permits sources to monitor valves for leaks less frequently if a leak is not detected for two successive months. [Footnote: See 40 C.F.R. § 265.1057(c)(1).] In addition, sources can skip quarterly leak detection periods for valves if a low percentage of valves are leaking. [Footnote: See 40 C.F.R. §§ 265.1062(b)(2), (3).]

EPA should apply the same testing and compliance flexibility in the final rule for boilers/process heaters that can demonstrate minimal change between annual tune-ups. Minimal change could be defined as less than a 25% change in CO emissions. [Footnote: Including a minimal threshold in the final rule will provide an incentive for assuring that the boiler is optimally tuned without the consequence of requiring a tune-up the next year if an adjustment is made in an attempt to reduce CO emissions. For example, a boiler with an initial reading of 8 ppm CO and a reading at the end of the prior year tune-up of 7 ppm CO may not necessarily be experiencing performance problems. The difference from 7 to 8 ppm CO may be caused by variations in the weather or the instrument and may not be an indication of decreased performance. The only way to verify that the boiler is at the optimal CO level is to adjust the burner. If attempts are made to tune the boiler and the CO decreases from 8 to 7 ppm CO, this should not be considered a significant adjustment which requires a tune-up in the following year. The minimal decrease from 8 to 7 ppm CO may be attributed to weather/instrument variations and not an indication of boiler performance calibration drift. If there is a significant improvement as indicated by decreased CO emissions, then the boiler should be re-visited in the following year to verify stable operations.] The Auto Group suggests that EPA insert in § 63.7540(a)(10) the following language to reflect the concepts discussed above:

If last two tune-ups performed pursuant to (a)(10) of this section did not require more than minimal (less than a 25 percent change in the CO ppm) adjustment of the burner or the air-to-fuel ratio as required by (a)(10)(ii) and (iii) of this section, the owner or operator of a boiler or process heater in the Gas 1 (NG/RG) subcategory with a heat input capacity of greater than 100 million Btu per hour shall be allowed 26 months from the last tune-up to conduct the next tune-up.

Such language would provide those sources that have boilers/process heaters that remain within unit specifications with additional flexibility as well as recognize that smaller boilers require minimal adjustments between tune-ups.

Response: The final rule does not incorporate the requested compliance flexibility for units that demonstrate that several consecutive tune-ups have produced minimal improvements in boiler operation as identified by decreases in CO emissions. The commenter did not provide sufficient justification that tune-ups conducted less frequently impact emissions. Further, technical literature provided by a Sustainable Energy Authority in Ireland relates the efficiency of a boiler to the frequency of the tune-up. Improved efficiency, reduces fuel consumption and in turn, emissions associated with fuel-based HAP. See preamble for justification of the work practice standards retained in the final rule.

Commenter Name: Britt S. Fleming
Commenter Affiliation: Auto Group
Document Control Number: EPA-HQ-OAR-2002-0058-2775.1
Comment Excerpt Number: 21

Comment: A Boiler or Process Heater That Has Not Operated in the Previous Year Should Be Allowed to Skip the Annual Tune-up Requirements in §§ 63.7540(a)(10) and (11).

The proposed work practices requirement for natural gas-fired boilers and process heaters in §§ 63.7540(a)(10) and (11) do not take into account the operational status of a unit and should allow more flexibility when boilers or process heaters are not operational or have not operated in the past year. As facilities change operational practices, the operational demand for a boiler may not be present and the boiler may be kept in standby for a period of time. Thus, if a boiler is not in use, an owner or operator of the unit should not be required to startup and operate the boiler just for the sake of performing a tune-up.

The Auto Group recommends that EPA amend the language in §§ 63.7540(a)(10) and (11) to include the following text indicated in underline to address this issue:

(10) If your boiler or process heater is in either the Gas 1 (NG/RG) or Metal Process Furnace subcategories and have a heat input capacity of 10 million Btu per hour or greater, you must conduct a tune-up of the boiler or process heater annually to demonstrate continuous compliance as specified in paragraphs (a)(10)(i) through (a)(10)(vi) of this section. A boiler that is not operating when the annual tune-up is due must perform the tune-up within 60 days of resuming operation.
* * *

(11) If your boiler or process heater has a heat input capacity of less than 10 million Btu per hour, you must conduct a tune-up of the boiler or process heater biennially to demonstrate continuous compliance as specified in paragraphs (a)(10)(i) through (a)(10)(vi) of this section. A boiler that is not operating when the biennial tune-up is due must perform the tune-up within 60 days of resuming operation.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2761.1, excerpt 4 for a response to tune-up frequency for limited use combustors.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 23

Comment: The costs for initial tune-ups and energy audits were annualized over 5 years. We do not believe it is appropriate to annualize these costs over a period of years, as these are services, and they must be paid in year 1 to the individual or company performing the work.

Response: EPA considers it appropriate to annualize the cost of a tune-up because the initial tune-up involves more costly steps that make subsequent tune-ups less costly. This is discussed in the docketed memorandum Revised Methodology for Estimating Control Costs for Industrial,

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Commenter Name: Stephen R. Gossett
Commenter Affiliation: Eastman Chemical Company
Document Control Number: EPA-HQ-OAR-2002-0058-3137.1
Comment Excerpt Number: 34

Comment: The proposed tune-up frequencies should be relaxed.

Table 3 of the proposed rule would require a tune-up every two years for boilers and process heaters under 10 mmBtu/hr(we note this table states only boilers required tune-ups – we assume EPA intends for process heaters to also subject to this requirement) and annually for units over 10 mmBtu/hr. Given the huge number of these units and the very small potential CO emissions, we believe these frequencies should be relaxed to once every 5 years for units smaller than 10 mmBtu/hr and to biennially for units over 10 mmBtu/hr. One problem with requiring annual tune-ups is that this requirement is likely to interfere with scheduled maintenance outages and force a shutdown earlier than otherwise needed. Also, some units are not used continuously and the requirement should be changed to require these tune-ups after so many operating hours, rather than so much elapsed time.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-3213.1, excerpt 112 for a response to tune-up requirements.

Commenter Name: Stephen R. Gossett
Commenter Affiliation: Eastman Chemical Company
Document Control Number: EPA-HQ-OAR-2002-0058-3137.1
Comment Excerpt Number: 35

Comment: The proposed requirement to minimize CO emissions during the tune-ups will conflict with many units' requirement to meet NOx emission limits.

§63.7540(a)(10)(iv) requires that the CO emissions be minimized consistent with manufacturer's specifications. First, many units are so old, there will be no manufacturer's specifications. Second, many units perform periodic tune-ups to minimize NOx as part of RACT requirements. It is well known that CO and NOx emissions are generally inversely related.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2761.1, excerpt 5 for a response to flexibility with respect to manufacturer's specifications and tune-ups. Refer to DCN EPA-HQ-OAR-2002-0058-2506.1, excerpt 13 for a response the consequences of minimizing CO.

Commenter Name: Stephen R. Gossett
Commenter Affiliation: Eastman Chemical Company
Document Control Number: EPA-HQ-OAR-2002-0058-3137.1
Comment Excerpt Number: 36

Comment: The tune-up requirements should allow use of portable analyzers that measure on a wet basis.

§63.7540(a)(10)(v) requires measurement of the CO & O2 concentration in parts per million, dry basis in the effluent stream. EPA should specify it is permissible to use a portable electrochemical analyzer that meets EPA Method CTM-034. This will measure CO, O2, & NOx from stationary combustion sources. However, it does not measure on a dry basis, but we see no reason for this to be a requirement. At one Eastman facility, it's Title V permits already require use of this method for periodic monitoring to measure NOx on our four NSPS Subpart D boilers. This would be a less expensive method of determining the CO concentration than having to hire a testing contractor.

Eastman requests that the moisture removal system described in this method be allowed as measurement on a dry basis.

Response: EPA agrees that the measurements do not need to be conducted on a dry basis, and that language has been removed from the rule so that the types of portable monitors mentioned by the commenter, as well as other portable monitors, can be used in the tune-up process.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 112

Comment: We believe proposed §63.7540(a)(10)(i)-(iii) reflect typical tune-up activities. Many jurisdictions require annual boiler inspections for safety reasons and boilers are often spared or can be shutdown when weather conditions are mild. Some jurisdictions require such inspections for process heaters particularly as part of a NOx minimization effort. However, not all boilers and few process heaters can be readily shutdown. The proposed (a)(10)(i) and (ii) burner inspections could require such a shutdown, since burners are not always retractable and cannot always be inspected or cleaned with the process heater in service. In those cases where the boiler or process heater is not spared or cannot be shutdown without impacting steam or process heat consumers this requirement should allow for delaying the burner inspection until the unit can be shutdown without impact. Potential unit and process shutdowns were not considered in evaluating the tune-up emissions impacts, costs or burdens and are not justified. EPA should clarify that boiler and process heaters need not shutdown to accomplish the required inspections or to clean burners. For units such as process heaters that do not shut down for extended periods of time, scheduling flexibility must be provided so that tune-ups can be done in association with normal inspection/overhaul schedules. For example, in the GHG Reporting rule, EPA allows for postponing initial or subsequent calibrations until the next scheduled maintenance outage (40 CFR 98.3(i)(6), 74 Fed. Reg. 56381). A similar approach should be used for scheduling of tune-ups on equipment which does not lend itself to an annual frequency.

Response: EPA agrees with the commenter. As long as owners/operators complete the parts of the tune-up that can be completed, they can postpone impractical requirements until the next scheduled outage, whichever comes first.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 113

Comment: Proposed §63.7540(a)(10)(iii) requires "Inspect the system controlling the air-to-fuel ratio, and ensure that it is correctly calibrated and functioning properly." This wording presumes an automatic air-to-fuel ratio controller, but those are present on a minority of process heaters. Where metered fuel/air control systems with O2 trim is installed, there is no real need for periodic "tune-ups" since combustion is continually optimized. Rather, burner/combustion system inspections, control equipment calibrations, and operational checks are all that should be needed to verify proper operation. EPA should reword the work practice requirements so that sources have flexibility to adapt procedures as most applicable and appropriate for specific sources.

Many units only have automatic draft control and individual, manual burner air control. For smaller units, draft control may be manual. Adding automatic air-to-fuel controls, as this requirement might be interpreted to require, is a very large, unjustified cost for units that do not have it, because it requires adding a forced draft combustion air system and perhaps an induced draft system. No such step was considered in the record and it is not justified.
EPA should reword §63.7540(a)(10)(iii) as follows "Inspect the draft control and burner air control systems to ensure they are operating properly. Inspect the system controlling the air-to-fuel ratio, if any, and ensure that it is correctly calibrated and functioning properly."

Response: EPA agrees with the commenter that air-to-fuel ratio controllers were not envisioned as a requirement for all units. Therefore, EPA is amending the language in §63.7540(a)(10)(iii) to require affected sources to inspect the ratio, as applicable. Refer to DCN EPA-HQ-OAR-2002-0058-2786.1, excerpt 15 for a response to tune-up requirements.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 114

Comment: Proposed §§63.7540(a)(10)(iv) and (v) are not typical tune-up requirements for either boilers or process heaters and do not reflect MACT. State tune-up requirements require minimization of NOx, not CO. Thus, these subparagraphs do not reflect the State requirements and would violate the State tune-up requirements for minimizing NOx. Additionally, the tune-up requirement conflicts with the proposed energy assessment work practice requirements, because tuning a boiler or process heater for minimum CO generally requires increasing excess air, which increases energy consumption, in direct conflict with the energy assessment directive to decrease energy consumption.

If the draft control on a boiler or process heater is working properly, as (a)(10)(iii) confirms, and there are no mechanical problems with the flame pattern, as (a)(10)(ii) confirms, there is no justification for measuring CO, since CO will be very low when these items are operating properly and because these are the things you would check and correct if CO were high. Furthermore, the mass of POM emissions that might be reduced from a gas fired boiler or process heater is insignificant. These CO measurement requirements should be removed. If they are not removed they must be justified versus the NOx emissions increase they will engender and EPA must consider policy implications and legality of whether the rule can specifically override State requirements to minimize NOx. The O2 level in a boiler or process heater also must consider draft limitations, flame impingement, and flame stability to assure a safe, reliable and efficient operation, and these conditions are not recognized in the EPA tune-up procedure.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2506.1, excerpt 13 for a response the consequences of minimizing CO. Refer to DCN EPA-HQ-OAR-2002-0058-3213.1, excerpt 117 for a response the definition of a tune-up.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 115

Comment: If burner/control adjustment relative to CO emissions is maintained in the tune-up procedure, the following changes are needed to reflect EPA's description of this work practice, the Agency cost and burden estimate, to make the CO adjustment practical, and not to have it result in increased NOx and other emissions.
i. It should be clarified, in regulatory language, that the CO is only to be minimized to the extent the adjustments do not increase NOx emissions, decrease unit combustion efficiency, cause flame impingement or flame instability, or cause other safety issues, and that portable CO and O2 analyzers are acceptable, and that these tests are not performance tests. Further, it should be made clear that the tuning is to be done at a single representative operating rate. Neither the rulemaking record nor combustion principles justify multipoint tune-ups, especially when some units basically operate at a fixed rate.
ii. For a short term adjustment situation, unit firing and stack conditions will not change enough for the stack moisture to vary significantly. Comparing CO measurements on either a wet or dry basis, before and after adjustment, is more than adequate to reflect the impact of adjustments.

iii. The oxygen measurement should be specified to be based on either an O2 CEMS reading, if the unit has one, or measurement using a portable emissions monitor. It should be made clear that a Method 3 oxygen measurement is not required.
EPA should not finalize proposed §§63.7540(a)(10)(iv) and (v). If these requirements are maintained, they should be simplified and clarified as discussed in items i – iii, above and EPA must specifically over-ride State tune-up requirements to minimize NOx and/or O2.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2506.1, excerpt 13 for a response the consequences of minimizing CO. Refer to DCN EPA-HQ-OAR-2002-0058-3137.1, excerpt 36 for a response to handheld instruments.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 116

Comment: Proposed §63.7515(e) requires that annual tune-ups be performed between 10 and 12 months after the previous tune-up. This means the tune-ups will be more frequent than on an annual basis, a fact not reflected in the record, and will make compliance difficult, because the source will not be able to do the tune-up at the same time each year. For instance if a tune-up is done in May one year, it must be done in April or May of the following year. Since good practice requires some allowance for problems and possible delay due to process operation issues, prudent sources will perform the tune-up in April. Then the next year's tune-up would be in March, etc. Under the proposed system, the work practice is actually required more frequently than annually, a fact not reflected in the record or cost analyses, and obviously not justified. We suggest §63.7515 be revised to specify that annual tune-ups may be done at any time in the same calendar quarter as the initial tune-up was done, regardless of the particular month in which the tune-up occurred. If a boiler or process heater does not operate during the quarter, the tune-up should be required within 30 days after restart.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2960.1, excerpt 81 for a response to scheduling of tune-ups.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 117

Comment: The definition of "Tune-up" is provided on 75 Fed. Reg. 32065. It correctly stipulates "optimize the combustion efficiency," whereas language noted above in 7540(a)(10) requires "minimize total emissions of CO," which as noted above is an incorrect approach to a tune-up and will lead to lower efficiency and higher net total emissions. As indicated above, EPA needs to correct language in 7540.

Response: The definition of "Tune-up" was removed from 40 CFR 63.7575 because all of the requirements for a tune-up are provided in the rule language at 40 CFR 63.7540(a)(10), making the definition unnecessary.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 118

Comment: The "tune-up" definition implies that use of an approved specialist could be required. EPA needs to recognize that many companies have in-house resources who are already well qualified, and already do perform adjustments to burner systems. Continued use of these resources must be supported.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2761.1, excerpt 5 for a response to flexibility with respect to manufacturer's specifications and tune-ups.

Commenter Name: Trent A. Dougherty
Commenter Affiliation: Ohio Environmental Council
Document Control Number: EPA-HQ-OAR-2002-0058-2789.1
Comment Excerpt Number: 3

Comment: We support inclusion of a biennial boiler tune-up requirement in the rule for applicable small (less than 10 million Btu input per hour) boilers as a means to enhance energy efficiency (and specifically combustion efficiency) and reduce toxic HAP emissions. We suggest clarification as to whether the proposed rule would require tune-up solely of the combustion systems of boilers or of the entire boiler (or furnace) system. We recommend the broader form of tune-up, which would allow additional efficiency measures to be addressed beyond combustion control.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2938.1, excerpt 1 for a response the inclusion of work practices. Refer to DCN EPA-HQ-OAR-2002-0058-2921.1, excerpt 1 for a clarification of the tune-up requirements.

Commenter Name: Walter Tyler
Commenter Affiliation: Invista
Document Control Number: EPA-HQ-OAR-2002-0058-2761.1

Comment Excerpt Number: 3

Comment: INVISTA, like other chemical manufacturers, has process heaters that are in dedicated service to specific chemical manufacturing process units, which are intended to run up to approximately three years between scheduled maintenance turnarounds. On a regular basis and consistent with process safety regulations, standards, and good operating practices, these heaters are inspected and any required preventative maintenance is performed at the end of these multi-year process runs during the scheduled unit turnaround. The proposed requirement to complete an annual tune-up would place facilities in the position of having to shut down an entire production unit to complete the heater tune-up. These more frequent production unit shutdowns and subsequent startups will result in additional emissions from the production unit (e.g., due to vessel purges). In addition to potentially generating additional emissions, process unit startups and shutdowns present the greatest safety risk to plant personnel. Adding startups and shutdowns, therefore, could increase the overall safety risk at these plants.

Recommended Text at 63.7540(a)(10):
If your boiler or process heater is in either the Gas 1 (NG/RG) or Metal Process Furnace subcategories and have a heat input capacity of 10 million Btu per hour or greater, you must conduct a tune-up of the boiler or process heater in each calendar year in which the unit operates annually, or at the next scheduled unit turnaround, to demonstrate continuous compliance as specified in paragraphs (a)(10)(i) through (a)(10)(vi) of this section.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-3213.1, excerpt 112 for a response to tune-up requirements.

Commenter Name: Walter Tyler
Commenter Affiliation: Invista
Document Control Number: EPA-HQ-OAR-2002-0058-2761.1
Comment Excerpt Number: 4

Comment: In addition, with respect to Item 2 in Table 3, the possibility exists for an affected unit to be in the site's Title V operating permit, even if it does not run during a calendar year. In this case, the intent of this requirement would be met if the unit is allowed to conduct the required tune-up during the next calendar year in which the unit operates. Without this modified language (see below) a site could be required to start an affected unit for the sole purpose of conducting the annual tune-up. As stated above, these additional startup and shutdown periods could result in increased emissions and increased overall safety risk at the facility. Accordingly, INVISTA suggests that the language in Item 2 of Table 3 be modified as follows:

Recommended Text at Table 3, Item 2:
Conduct a tune-up of the boiler in each calendar year in which the unit operates annually, or at the next scheduled unit turnaround, as specified in § 63.7540

Response: We have not modified the language in Table 3, but have made some exceptions in § 63.7540 to the annual and biennial frequency to account for units with continuous processes that exceed these time frames. EPA has also incorporated a biennial tune-up frequency for limited use units. The fact that these units operate for unpredictable periods of time and limited hours, would require units to start up solely for the purposes of implementing a tune-up, which is economically impracticable, and would lead to increased emissions and combustion of fuel that would not otherwise be combusted. Therefore, we are regulating these units with a work practice standard that requires a biennial tune-up, which will limit HAP by ensuring that these units operate at peak efficiency during the limited hours that they do operate.
EPA agrees that a unit that is not operating should not be started up for the express purpose of conducting a tuneup. To ensure that tune-ups are as effective as possible and do not result in excess emissions, for units that are not operating on the required date for a tune-up, the tune-up must be conducted within one week of startup.

Commenter Name: Walter Tyler
Commenter Affiliation: Invista
Document Control Number: EPA-HQ-OAR-2002-0058-2761.1
Comment Excerpt Number: 5

Comment: Many combustion units have manufacturer's specifications. However, older units may not have written manufacturer's specifications available. In these cases, best practices have been developed by combustion unit experts. It is important to allow the use of these best practices when tuning older units.

Recommended Text at 63.7540(a)(10)(iv):
Minimize total emissions of CO consistent with the manufacturer's specifications, where available, or consistent with unit-specific best practices for operation of the unit.

Response: Because manufacturer's specifications may not be available for all units and because of unique design considerations that may impact a given units ability to meet the specific tune-up requirements, the language in 63.7540(a)(10)(i) through (iv) has been amended.

Commenter Name: Walter Tyler
Commenter Affiliation: Invista
Document Control Number: EPA-HQ-OAR-2002-0058-2761.1
Comment Excerpt Number: 6

Comment: There is no language addressing how this measurement should be completed. We request specific language to provide clarity and certainty of compliance obligations. When boiler/process heater tune-ups are conducted, handheld instruments are often used by the boiler/process heater experts. Specifying that handheld instrumentation is acceptable to meet this requirement would provide the necessary clarification and would meet the intent of this provision. Requiring a complete Method 10 test, on the other hand, would add significant additional cost without any additional improvement in the tune-up results. Specifically, such testing would require mobilization of a stack testing firm before the tune-up and after the tune-up in order to meet the requirement.

Recommended Text at 63.7540(a)(10)(vi)(A):
The concentrations of CO in the effluent stream in ppmvd, and oxygen in percent dry basis, measured (using handheld combustion gas analyzers or other measurement instrumentation) before and after the adjustments of the boiler.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-3137.1, excerpt 36 for a response to handheld instruments.

Commenter Name: Walter Tyler
Commenter Affiliation: Invista
Document Control Number: EPA-HQ-OAR-2002-0058-2761.1
Comment Excerpt Number: 7

Comment: Units of this size may not be operated, even within a two-year period. For consistency with the larger Gas 1 unit requirements, we recommend the following revisions:

Recommended Text at 63.7540(a)(11):
If your boiler or process heater has a heat input capacity of less than 10 million Btu per hour, you must conduct a tune-up of the boiler or process heater during each rolling biennially period in which the unit operates to demonstrate continuous compliance as specified in paragraphs (a)(10)(i) through (a)(10)(vi) of this section. If the affected unit is part of a process that has longer than a two-year period between scheduled turnarounds, the tune-up shall be completed at the next scheduled turnaround.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2761.1, excerpt 4 for a response to tune-up frequency for limited use combustors.

Commenter Name: William R. Ermatinger
Commenter Affiliation: Northrop Grumman
Document Control Number: EPA-HQ-OAR-2002-0058-2506.1
Comment Excerpt Number: 13

Comment: The tune-up procedure described in proposed §63.7540 requires minimization of CO emissions as an intended means of minimizing HAP emissions, because EPA proposes to utilize CO as a surrogate for HAPs. However, adjustment of boilers or process heaters with a focus of minimizing CO emissions usually results in suboptimal performance with respect to fuel efficiency, steam generation rate and cost of operation, thereby wasting fuel and increasing emissions of other pollutants, including the other HAPs to be regulated under the Boiler MACT, and also the recently regulated greenhouse gases. Because the typical level of CO at the point of highest operating efficiency is not significantly higher than at its minimized level, adjustment of CO to a minimum level without regard to other desirable aspects of operation as proposed is unwarranted.

Response: In the final rule we have modified the requirements of the tune-up to optimize CO emissions instead of “minimize” CO emissions in order to balance the concerns of flame instability and increased NOx emissions. This approach is consistent with most state tune-up programs and manufacturer specifications, which suggest minimizing NOx emissions while optimizing other aspects of the combustion system.

Commenter Name: William R. Ermatinger
Commenter Affiliation: Northrop Grumman
Document Control Number: EPA-HQ-OAR-2002-0058-2506.1
Comment Excerpt Number: 14

Comment: The point of highest boiler efficiency generally occurs at a particular boiler load and steam output. Deviating from this point will result in less than peak efficiency, but continuous operation at the peak efficiency point is not usually practical because of routine load variations. Only "base loaded" boilers have the potential to be operated at a relatively steady state, but even base loaded units must be designed to "float" with changing steam demands in an industrial environment.

Response: EPA is mindful of the need to account for sources’ variability and the practical impact boiler load has on combustion efficiency. However, the annual and biennial tune-ups requirements will adequately ensure combustion efficiency is maintained in discrete intervals. The tune-up requirements are not mandating a continuous operation at peak efficiency.

Commenter Name: William R. Ermatinger
Commenter Affiliation: Northrop Grumman
Document Control Number: EPA-HQ-OAR-2002-0058-2506.1
Comment Excerpt Number: 17

Comment: As such, these requirements are outside the scope of EPA’s authority under §112(d) of the CAA and should be removed in entirety from the proposal. A more viable approach to assuring lowest HAP emissions of an industrial boiler over the long term would be to establish the most efficient operating range and then utilize the same parameters monitored by the control system as surrogate parameters for HAP minimization.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2506.1, excerpt 13 for a response the consequences of minimizing CO.

Commenter Name: William R. Ermatinger
Commenter Affiliation: Northrop Grumman
Document Control Number: EPA-HQ-OAR-2002-0058-2506.1
Comment Excerpt Number: 18

Comment: The requirement for additional certified energy assessments and tune-ups adds an unnecessary cost and administrative burden. Large industrial facilities already manage their boiler efficiency as a routine cost control technique. Adding an additional administrative burden and cost will not serve to significantly improve the existing processes.

Response: The EPA agrees that some sites already perform regular tune-ups, which means the requirement will not increase costs for those facilities. Based on data received from the ICR survey, not all units reported annual tune-ups as part of a good combustion practice and EPA determined that regulating the frequency and components of the tune-up would maximize combustion efficiency in this source category.

Commenter Name: Robert D. Morrison
Commenter Affiliation: Abbott Laboratories
Document Control Number: EPA-HQ-OAR-2002-0058-2764.1
Comment Excerpt Number: 22

Comment: Greater flexibility should be provided on the timing and use of tune-ups as work practices for small boilers and Gas 1 boilers (40 CFR 63.7515(e), 75 FR 32052). Section 63.7515(e) requires a tune-up interval of 10 to 12 months from the previous tune-up. This could result in more frequent tune-ups than the nominal “annual” frequency over time. As an alternative, scheduling for tune-up should be allowed to vary within a range that includes a shorter and longer period (e.g. between 10.0 and 14.0 months), or simply require a tuneup during each calendar year. This would allow flexibility to coordinate shutdowns for tuneups among multiple units and ensure availability.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-3213.1, excerpt 112 for a response to tune-up requirements.

Commenter Name: Donald R. Schregardus
Commenter Affiliation: Department of Defense
Document Control Number: EPA-HQ-OAR-2002-0058-2763.1
Comment Excerpt Number: 22

Comment: The requirement to conduct annual tune-ups of gas-fired boilers (heat input capacity of 10MMBtu/hr or greater) does not include a qualification whereby limited-use boilers would be required to conduct tune-ups less frequently than normal operational boilers. The consequence of this is that boilers that operate only in a back-up capacity would be required to undergo annual tune-ups despite operating zero hours or only a few hundred hours during the year. The resultant unintentional effect of universally applying the tune-up requirement is that HAP emissions will unnecessarily increase due to operating boilers solely for the purpose of conducting a tune-up.

At some military bases, over 50% of natural gas boilers of heat input capacity of 10 MMBtu/hr or greater are considered limited-use boilers, having an annual heat input capacity factor equal to, or less than, 10%. Several of these boilers typically will not be operated at all during the year due to being designated for back-up use only or for lack of system demand. Operating these boilers for the sole purpose of conducting annual tune-ups will increase HAP, criteria pollutant, and greenhouse gas emissions while consuming fuel and resources with no environmental benefit. Boiler manufacturers provide specifications for achieving optimum operational efficiency. Because boiler manufacturer recommendations may vary, language is being proposed to address limited-use boilers.

Add the following language at §63.7540(a) to the rule to address limited-use boilers.
The following Boiler MACT criteria shall apply for limited-use boilers to assure that the maximum degree of HAP reduction is achieved:

a. Limited-use gas boilers (heat input capacity of 10 million Btu per hour or greater) having an annual heat input capacity factor equal to or less than 10%, may conduct a tune-up biennially provided the owner or operator conducts monthly calculations to demonstrate that the boiler maintains limited-use status on a 12-month rolling basis.

b. If any limited-use gas boiler (heat input capacity of 10 million Btu per hour or greater) fails to maintain limited-use status on a 12-month rolling basis and a tune-up has not been completed in the previous 12-month period, then the owner or operator shall conduct a tune-up of the gas boiler within the next 90 day period following the month that the boiler fails to maintain limited-use status.

c. Gas boilers of any size that do not operate for any period of time during a biennial period shall not be required to conduct a tune-up for that same biennial period. Following the .first biennial period in which a gas boiler did not operate for any period of time, the owner or operator shall conduct a tune-up of the gas boiler within the next 90 day period following the first restart of the gas boiler.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2761.1, excerpt 4 for a response to tune-up frequency for limited use combustors.

Commenter Name: W. Randall Rawson
Commenter Affiliation: American Boiler Manufacturers Association
Document Control Number: EPA-HQ-OAR-2002-0058-2698.1
Comment Excerpt Number: 23

Comment: * ABMA acknowledges the proposed requirements for boiler tune-ups set forth in proposed 40 C.F.R. 63.7540(a)(10). While maintenance, repair and tune-up of boilers and combustion equipment in the >400,000 Btu/hr sector do have characteristics in common, ABMA notes that every boiler system is different depending on overall design, operational characteristics and use. Each boiler system in this sector is designed to a specific application; “cookie-cutter” designs do not apply to the non-residential boiler sector. Given such variability in design and operation, and the very real issue of safety as it pertains to (1) doing work with highly technical combustion systems and (2) operating those systems post-tune-up, it is important for tune-ups to be conducted by companies and personnel with the highest standards of technical training and practical expertise in addressing issues of maintenance, repair and optimization of boiler systems. The manufacturers of boilers, burners, or boiler components are a logical source of expertise, as are representatives and boiler repair companies that have documented arrangements with manufacturers. Further, tune-ups should be conducted in accordance with manufacturer guidelines and recommendations in order to preserve technical warranties and guarantees.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2761.1, excerpt 5 for a response to flexibility with respect to manufacturer’s specifications and tune-ups.

Commenter Name: Melvin E. Keener
Commenter Affiliation: Coalition for Responsible Waste Incineration (CRWI)
Document Control Number: EPA-HQ-OAR-2002-0058-2824.1
Comment Excerpt Number: 25

Comment: CRWI supports the use of a periodic tune-up-as a work practice for gas-fired boilers. However, we would suggest that the schedule be made more flexible.

The tune up must be done when the unit is shut down. While some facilities shut down their unit for maintenance on an annual basis, others have maintenance cycles of 36 months or more, depend upon the facility’s production schedule, the boiler design, the fuel used, the load for that boiler and the annual hours of operations. Some facilities will have multiple boilers and only use part of them at any time Requiring a facility that has not been used in that calendar year to undergo an annual tune-up does not make sense.

Therefore, CRWI suggests that the Agency modify the timing for this requirement to match a facility’s routine maintenance schedule. There is no reason to develop a rigid schedule for something when a flexible schedule based on routine maintenance will be equally effective. CRWI suggests the following modifications to § 63.7540(a)(10) and Table 3.

63.7540(a)(10): If your boiler or process heater is in either the Gas 1 (NG/RG) or Metal Process Furnace subcategories and have a heat input capacity of 10 million Btu per hour or greater, you must conduct a tune-up of the boiler or process heater in each calendar year in which the unit operates-annually, or at the next scheduled unit turnaround, to demonstrate continuous compliance as specified in paragraphs (a)(10)(i) through (a)(10)(vi) of this section.

Table 3, Item 2:
Conduct a tune-up of the boiler in each calendar year in which the unit operates annually, or at the next scheduled unit turnaround, as specified in § 63.7540

Response: Refer to DCN EPA-HQ-OAR-2002-0058-3213.1, excerpt 112 for a response to tune-up requirements.

Commenter Name: Chris Greissing
Commenter Affiliation: Industrial Minerals Association
Document Control Number: EPA-HQ-OAR-2002-0058-2740.2
Comment Excerpt Number: 30

Comment: (e) If you are required to meet an applicable work practice standard, you must conduct annual performance tune-ups according to 63.7520. Each annual tune-up must be conducted between 10 and 12 months after the previous tune-up.

Conducting a tune-up would require a boiler outage. Annual outages are scheduled based on numerous business factors and can occur at a different time each year. This would make the narrow requirement of 10-12 months between tune-ups unnecessarily onerous and costly. Additionally, backup boilers may only operate a limited number of hours in any given year. It is impractical to conduct an annual tune-up on a unit that has operated 2500 hours since its last tune-up, for example. Therefore, the tune-up frequency should be based on the following criterion: once per calendar year but not sooner than at least 6000 hours of operation between tune-ups. This would require boilers operating on a continuous basis to undergo a tune-up once per calendar year but with separation between tune-ups of at least 6000 hours of operation. For backup units a tune-up would be required some time during the calendar year after the unit reached 6000 hours of operation since its last tune-up.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2761.1, excerpt 4 for a response to tune-up frequency for limited use combustors.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 70

Comment: Since there is no minimum design firing rate specified, tune-ups would be required for even the smallest boiler or process heater at a major source, such as those designed for laboratories, cafeterias and offices. Even the smallest boiler used for space heating would be covered. The proposal would even require tune-ups, permitting and similar burdens for such small units as laboratory and cafeteria steam generators, steam cleaners (e.g., carpet cleaners), gas-fired oil fryers for food and similar insignificant sources. The database supporting this rulemaking did not consider such small boilers and process heaters, nor did the cost and burden estimates consider them. Applying the tune-up requirements and the recordkeeping and reporting requirements to them will provide no benefit, and they should be excluded.

The State rules on which the tune-up requirement claimed to be based typically only apply the tune-up requirement to boilers and process heaters above a certain size. For instance, South Coast rule 1146 and N.J.A.C. 7:27 19.7 require combustion tune-ups for boilers and process heaters over 5 MMBTU/hr design firing rate.

Recommendation: Specify a 5 MMBTU/hr minimum design heat input capacity for making any of the requirements of this proposal applicable including notice and general provision requirements.

Response: EPA disagrees with incorporating a de-minimus level on the tune-ups. EPA expects many facilities will consolidate the recordkeeping system and implementation of tune-ups in order to reduce the costs of recordkeeping. Further, many boiler manufacturers recommend annual servicing of the unit. Similarly, small units located residential areas, such as home furnaces and boilers have similar recommendations for annual tune-ups in order to maintain good efficiency and safe use of the unit. The commenter does not provide sufficient justification why a routine tune-up of these small industrial/institutional/commercial boilers is an unreasonable requirement.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 71

Comment: EPA provides justification (not economically feasible) for units of ?10 MMBTU/hr to be subject to biennial tune-up requirements rather than annual. We believe that the EPA analysis actually underestimates the cost and overestimates the potential emission reductions and that the case for exempting small units from annual tune-up requirements is even stronger than EPA indicates. On that basis, we believe units < 100 MMBTU/hr should be subject a no more frequent tune-up requirement than biennial and that units < 10 MMBTU/hr should not be subject to the requirement at all. Emission reduction potential is overestimated because EPA overestimated the potential for problems in boilers and process heaters burning the clean Gas 1 fuels and because the Agency did not account for the increases in emissions that result from upsetting the boiler or process heater while inspecting the burner(s). Costs are higher than EPA estimates for the following reasons. We believe a realistic evaluation would show that such a requirement has negligible emissions impact

* EPA mistakenly assumed one burner per unit.

* EPA did not account for the cost and effort in accessing the burner(s) in forced air units.

* EPA did not account for the stack access costs or the moisture measurement cost.

* EPA did not account for the cost of determining stack moisture or the costs that come from making the tune-up as a performance test (as discussed in Comments V.5 and V.6.)

Recommendation: Change the tune-up frequency to biennial for units of <100 MMBTU/hr and eliminate the tune-up requirement for units under 10 MMBTU/hr.

Response: In the final rule EPA has adjusted the language to indicate "as applicable" for many of the tune-up requirements. EPA has also modified the CO measurement basis to remove the requirement to measure stack moisture, as long as all measurements of CO are made on the same basis. EPA has also made certain exceptions to the schedule of tune-ups for units who have two or 3 year continuous processes in order to avoid increased emissions from upsetting these boilers while they are in mid-process. As a result, many units identified in the proposal as requiring certain aspects of a tune-up will not realize these costs. Furthermore, EPA disagrees that the emission reductions have been overestimated. EPA expects work practice standards such as boilers tune-ups will improve the efficiency of boilers, resulting in fuel savings and pollution prevention. EPA has determined that boiler tune-up improve the efficiency of a boiler 1 percent; this conservative estimate was extracted from the technical literature.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 73

Comment: Annual tune-ups intended to minimize CO emissions are proposed for existing boilers and process heaters with a design heat duty of >10 MMBTU/hr that fire Gas 1. Biennial tune-ups are required for units with a design heat input <10 MMBTU/hr regardless of what type of gas they combust. We do not believe such tune-ups are MACT, as EPA claims on Page 32025 of the proposal preamble. The basis for EPA's conclusion that a tune-up for minimizing CO is MACT is the claim that many States require tune-ups. While this is correct to some extent, these State tune-ups typically are for the purpose of minimizing NOx or optimizing combustion by minimizing O2 and do not require minimizing CO as EPA proposes. In fact, reducing CO using the tune-up procedure EPA proposes would violate the very tune-up requirements EPA cites, because reducing CO increases NOx and requires increasing O2. As we discuss in our next comments, it isn't even clear that the proposed tune-up would reduce any annual emissions, since the tune-up itself raises emissions while it is being done. Thus, while we believe a simple, non invasive inspection work practice might add some value and meet the requirements of 112, the proposal to use the tune-up to minimize CO emissions should not be finalized as presented.

Recommendation: Do not finalize proposed 63.7540(a)(10)(iv) and (v). If these requirements are maintained, they should be simplified and clarified and EPA must specifically override State regulations that require minimizing NOx and/or O2 or optimizing combustion efficiency.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2506.1, excerpt 13 for a response the consequences of minimizing CO.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 75

Comment: The true impacts of the 63.7540(a)(10)(i)-(iii) inspections should be characterized and documented by the Agency in the record. The evaluation in the proposal record seems to assume each unit has one or two burners that are readily inspected. This may be true for some units, particularly boilers and some smaller process heaters. But many units, particularly larger process heaters, have a multitude of individual burners (tens to hundreds), and these are often not easily accessible for inspection, such as in the case of forced combustion air systems, where duct work limits easy access. For those units, costs and burdens will be much higher than EPA estimates because of the vastly higher number of burners to inspect and the added cost and effort of opening ductwork to allow the inspection.

Recommendations: Adjust the estimated costs for the tune-up work practice and reevaluate its justification.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2960.1, excerpt 71 for a response to underestimated tune-up costs.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 77

Comment: Proposed 63.7540(a)(10)(iii) requires "Inspect the system controlling the air-to-fuel ratio, and ensure that it is correctly calibrated and functioning properly." This wording presumes an automatic air-to-fuel ratio controller, but those are present on a minority of process heaters. Many units only have automatic draft control and individual, manual burner air control. For smaller units, even draft control may be manual. Adding automatic air-to-fuel controls, as this requirement might be interpreted to require, is a very large, unjustified cost for units that do not already have it because it requires adding a forced combustion air system and perhaps an induced draft system. No such step was considered in the record.

Recommendation: Reword 63.7540(a)(10)(iii) as follows "Inspect the draft control and burner air control systems to ensure they are adjusted and operating properly. Inspect the system controlling the air-to-fuel ratio, if any, and ensure that it is correctly calibrated and functioning properly."

Response: Refer to DCN EPA-HQ-OAR-2002-0058-3213.1, excerpt 113 for a response to flexibility with respect to an air-to-fuel ratio controller.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 78

Comment: Proposed 63.7540(a)(10)(iv) and (v) are not typical tune-up requirements for either boilers or process heaters and do not reflect MACT, and their significant costs are not reflected in the rulemaking record. As we pointed out in Comment V.C.1, State tune-up requirements typically require minimization of NOx or optimization of combustion efficiency, not minimization of CO. Thus, these subparagraphs do not accurately reflect the State requirements, are not MACT and would, in fact, violate the State tune-up requirements for minimizing NOx. Minimizing CO would require units to operate at less efficient higher excess O2 levels. Additionally, the tune-up requirement conflicts with the proposed energy assessment work practice requirements, because tuning a boiler or process heater for minimum CO increases energy consumption, in direct conflict with the energy assessment directive to decrease energy consumption.

Both paragraphs require that the source have or contract for CO and O2 monitors [Footnote: We presume this is the Agency intent in these requirements, though the language in propose d63.7515 and 63.7520 could be read as requiring a Method 10 performance test for these before and after measurements. This point should be clarified in the record and any final version of the rule which includes this requirement.] and (a)(10)(v) requires a moisture measurement on the stack gas. As discussed in other comments, these CO measurements appear to be treated as performance tests, resulting in additional costs and burdens, versus a less formal check. Costs and burdens for these measurements and their treatment as performance tests are not totally reflected in the record since it appears the significant cost of the moisture measurements, accessing the stack and performance test burdens were not included in EPA estimates. Additionally, as EPA points out in its 112(h) justification for these work practices, access to small stacks to allow such measurements isn‘t even feasible.

If the draft control on a boiler or process heater is working properly, as (a)(10)(iii) confirms, and there are no mechanical problems with the flame pattern, as (a)(10)(ii) confirms, there is no justification for measuring CO, since CO will be very low when these items are operating properly and because these are the things you would check and correct if CO were high. Furthermore, the mass of CO emissions and POM emissions that might be reduced from a gas-fired boiler or process heater is insignificant. These CO measurement requirements should be removed. If they are not removed they must be justified versus the NOx emissions increase they will engender and the rule must specifically override State requirements to minimize NOx. The O2 level in a boiler or process heater also must consider draft limitations, flame impingement and flame stability to assure a safe, reliable and efficient operation.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2506.1, excerpt 13 for a response the consequences of minimizing CO. Refer to DCN EPA-HQ-OAR-2002-0058-3137.1, excerpt 36 for a response to handheld instruments. Refer to DCN EPA-HQ-OAR-2002-0058-3213.1, excerpt 112 for a response to tune-up requirements.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-2702.1
Comment Excerpt Number: 79

Comment: A. Tune-ups are defined to minimize CO, but that will decrease efficiency and Will increase overall emissions.
In the Proposed Rule, the tune-up requirements are defined in such a way to reduce CO emissions without any consideration of efficiency and costs. 75 FR 32014. Specifically, the Proposed Rule requires minimization of CO "consistent with the manufacturer’s specifications." 75 FR 32014. This practice generally requires increasing excess air, temperature, costs, and even overall HAP emissions while decreasing efficiency. Additionally, lowering CO emissions for many units will result in an increase of NOx emissions. First, many units are so old, there will be no manufacturer’s specifications. Second, many units perform periodic tune-ups to minimize NOx as part of RACT requirements. It is well known that CO and NOx emissions are generally inversely related. Hamworthy Peabody Combustion (a CIBO member) provided the figure (see submittal for combustion performance figure) to indicate the general relationship of (excess O2 from peak efficiency), CO, NOx, and combustion efficiency for a gas fired burner. This shows relative changes from the peak efficiency point and is generally applicable in form for all fuels. As shown, attempts to focus on reducing CO emissions will lead to increased excess air operation, thereby increasing NOx emissions and decreasing unit efficiency. EPA has failed to recognize this basic reality of burner operation and the negative impact on NOx and energy efficiency, and rather, in their impacts analysis, assumed a 1% improvement in efficiency (75 FR 32037). While there may be units in operation that can improve efficiency, well tuned boilers and process heaters will generally increase NOx emissions and decrease efficiency if the only focus is on reducing CO emissions. In reality, optimum conditions are achieved with CO at some higher level. CIBO recommends that EPA amend the rule so that tune-ups also consider optimizing efficiency, limiting increases of NOx, and ensuring safety, not focusing on

minimizing CO. In fact, EPA is correct in its definition of "Tune-up" in that it specifies "to optimize combustion efficiency" (63.7575). In contrast, 63.7540(a)(10)(iv) stipulates "minimize total emissions of CO." The latter needs to be changed to recognize the need for optimization in recognition of all appropriate factors.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2761.1, excerpt 5 for a response to flexibility with respect to manufacturer's specifications and tune-ups. Refer to DCN EPA-HQ-OAR-2002-0058-2506.1, excerpt 13 for a response the consequences of minimizing CO. Refer to DCN EPA-HQ-OAR-2002-0058-3213.1, excerpt 117 for a response the definition of a tune-up.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 79

Comment: If the CO minimization portion of the tune-up is maintained, the following changes are needed to reflect EPA's description of this work practice, correct the Agency cost and burden estimate, to make the CO adjustment requirement practical, and not have the adjustment result in increased NOx and other emissions.

i. It should be clarified, in regulatory language, that the CO is only to be minimized to the extent the adjustments do not increase NOx emissions or firing or cause flame impingement or flame instability, that portable CO and O2 analyzers are acceptable, and that these tests are not performance tests. Further, it should be made clear that the tuning is to be done at a single representative operating rate. Neither the rulemaking record nor combustion principals justify multipoint tune-ups.

ii. The moisture measurement and correction requirements should be dropped. For a short term adjustment situation, unit firing and stack conditions will not change enough for the stack moisture to vary significantly. Comparing CO measurements on a wet basis, before and after adjustment, is more than adequate to reflect the impact of adjustments. The Method 4 moisture tests called for in the present proposal would impose a more than $10,000 cost per tune-up, a cost not considered in the Agency cost and burden analyses.

iii. The oxygen measurement and correction should be specified to be based on either an O2 CEMS reading, if the unit has one, or measurement using a portable monitor. It should be made clear that a Method 3 oxygen measurement is not required.

iv. All suggestions that the tune-up is a performance test should be removed.

Recommendation: Do not finalize proposed 63.7540(a)(10)(iv) and (v). If these requirements are maintained, they should be simplified and clarified as discussed in items i iv, above, and EPA must specifically over-ride State requirements to minimize NOx and/or optimize combustion.\

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2506.1, excerpt 13 for a response the consequences of minimizing CO. Refer to DCN EPA-HQ-OAR-2002-0058-3137.1, excerpt 36 for a response to handheld instruments.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-2702.1
Comment Excerpt Number: 80

Comment: EPA should acknowledge that portable combustion analyzers are acceptable. Proposed § 63.7540(a)(10)(v) requires measurement of the CO & O2 concentration in the effluent stream. 75 FR 32059. EPA should specify it is permissible to use a portable electrochemical analyzer that meets EPA Method CTM-034. This will measure CO, O2, & NOx from stationary combustion sources. This would be a less expensive method of determining the CO concentration than having to hire a testing contractor and many facilities already utilize portable analyzers.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-3137.1, excerpt 36 for a response to handheld instruments.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 81

Comment: Proposed 63.7515(e) requires that annual tune-ups be performed between 10 and 12 months after the previous tune-up. This means the tune-ups will be more frequent than annual, a fact not reflected in the record, and will make compliance difficult, because a source will not necessarily be able to do the tune-up at the same time each year. For instance, if a tune-up is done in May one year, it must be done in April or May of the following year. Since good practice requires some allowance for problems and possible delay due to process operation issues, prudent sources will perform the tune-up in April. Then the next year‘s tune-up would be in March, etc. Under the proposed system, the work practice is actually required more frequently than annually, a fact not reflected in the record or cost analyses. We suggest 63.7515 be revised to specify annual tune-ups may be done at any time in the same calendar quarter as the initial tune-up was done, regardless of the particular month in which the tune-up occurred. If a boiler or process heater does not operate during the quarter, the tune-up should be required within 30 days after restart.

Recommendation: Revise the tune-up frequency language so tune-ups may be done in the same calendar quarter as the initial performance test in years when they are due. Add provisions for boilers and process heaters that are out-of-service during the quarter they are due for tune-up.

Response: The final rule clarifies the tune-up requirements and provides additional flexibility in scheduling the tune-up. Each annual tune-up specified in §63.7540(a)(10) must be no more than 13 months after the previous tune-up. Each biennial tune-up specified in §63.7540(a)(11) must be conducted no more than 25 months after the previous tune-up.
EPA agrees that a unit that is not operating should not be started up for the express purpose of conducting a tuneup. To ensure that tune-ups are as effective as possible and do not result in excess emissions, for units that are not operating on the required date for a tune-up, the tune-up must be conducted within one week of startup.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-2702.1
Comment Excerpt Number: 81

Comment: Tune-up Scheduling Should Be Amended.
EPA has proposed that units conduct tune-ups between 10 to 12 months following completion of the previous tune-up. This essentially requires tune-ups to be conducted more frequently then on an annual basis. This is unreasonable as it does not incorporate the requisite flexibility for units. Allowing this flexibility is especially important for process heaters that run for extended periods (i.e. 2 to 5 years) so that internal inspections cannot be done annually.

CIBO supports amending the Proposed Rule so that tune-up frequencies are relaxed to once every 5 years for units smaller than 10 MMBtu/hr and to biennially for units over 10 MMBtu/hr. One problem with requiring annual tune-ups is that this requirement is likely to interfere with scheduled maintenance outages and force a shutdown earlier than otherwise needed. Also, some units are not used continuously and the requirement should be changed to require these tune-ups after so many operating hours, rather than so much elapsed time. EPA could modify the Proposed Rule to allow tune-ups to be done in conjunction with normal inspections and/or overhaul schedules. In order to determine applicability, EPA could require unit specific demonstration of extended operating times. If a unit is not operated for a period of time, EPA should provide that tune-ups be relative to elapsed operating time.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2874.1, excerpt 6 for a response to tune-up frequency. Refer to DCN EPA-HQ-OAR-2002-0058-3213.1, excerpt 112 for a response to tune-up requirements.

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-2702.1
Comment Excerpt Number: 82

Comment: Tune-ups Should Not Require Outside Certification of Adjustments.
Tune-up is defined in the Proposed Rule as "adjustments made to a boiler in accordance with procedures supplied by the manufacturer (or an approved specialist) to optimize the combustion efficiency." 75 FR 32065 (emphasis added). This definition limits the ability of an owner/operator to make adjustments to those that are done in accordance with procedures supplied by manufacturers or approved specialists. EPA should revise this to allow the owner/operator to establish and conduct appropriate procedures independent of this outside certification process. Many facilities have in-house specialists who are well-qualified to conduct optimization adjustments on units. In fact, in-house specialists have site specific information compared to the generic, and possibly in appropriate recommendations a manufacturer might provide. Many adjustments are not directly applicable to some units, particularly some process heaters. Therefore, all steps included in 63.7540(a)(10) should be qualified to only be used when appropriate for specific units. Generic procedures recommended by manufacturers and "approved specialists" will not always result in the appropriate adjustments and EPA should recognize and allow use of the knowledgeable resources currently available in-house at many facilities and companies.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2761.1, excerpt 5 for a response to flexibility with respect to manufacturer's specifications and tune-ups.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 82

Comment: Because there will be many tune-ups at a typical major source, provision is needed to allow sources to move the tune-ups to other quarters, with agreement of the permitting authority. Tune-up personnel, site personnel and local Agency resources are limited and workload needs to be spread throughout the year to allow these resources to be efficiently utilized. In fact, for the same reasons, we would recommend sources be allowed to spread the initial tune-ups out over the year after the rule effective date rather than the 180 days provided.

Recommendations: Allow for changing tune-up timing to allow sources to spread out the effort throughout a year.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2960.1, excerpt 81 for a response to scheduling of tune-ups.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-2702.1
Comment Excerpt Number: 83

Comment: Tune-ups are Inapplicable For Some Units.
As currently proposed, EPA's tune-up requirements are unworkable for certain units to which they apply. EPA should amend the work practice standards to reflect these discrepancies. Specifically, the tune-up procedures require owners and operators to inspect "the system controlling the air-to-fuel ration, and ensure that it is correctly calibrated and functioning properly." 75 FR 32014. This requirement is simply inapplicable to units that utilize metered fuel-air control systems with continuous excess air (O2) control where combustion is optimized continuously. On these units, EPA should recognize that system inspections, equipment calibrations, and operational checks are sufficient to ensure the system is "calibrated and functioning properly." Flexibility is what is needed, and EPA should incorporate in the tune-up requirements room for sources to utilize or modify procedures as applicable for and as needed to optimize specific units based on their design and operation.

Response: EPA agrees with the commenter and has changed some of the language regarding tune-ups to increase the flexibility of the requirements. Regarding the specific comment, units that continuously optimize the air-to-fuel ratio would satisfy the language, even as proposed, through a system inspection, equipment calibration, and operational check (as suggested by the commenter as an appropriate method of meeting the requirement).

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 282

Comment: It appears that EPA attempted to estimate the cost impact of the tune-up requirement using very limited information, which was extrapolated to the entire population of units affected by the BPH NESHAP. A survey of several of companies involved in tune-ups and studies revealed that tune-up costs are highly variable dependent upon unit-specific consideration. Based on refined cost information developed from our independent research indicating that EPA underestimated "per facility costs", as well as apparent inappropriate assumptions regarding the complexity of certain industry categories, we believe that it is likely that EPA has significantly underestimated costs for Gas 1 annual tune-ups. API's total estimated cost for tune-ups for the Gas 1 subcategory is approximately $24 million; however, because EPA did not provide a detailed breakout of tune-up costs for the Gas 1 subcategory, we are unable to provide further specific comment on the methodology or approach used to derive this estimate.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2960.1, excerpt 71 for a response to underestimated tune-up costs.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 307

Comment: Tune-up costs will vary substantially based on a number of factors including but not limited to the following: source type, design, number of burners, capacity, fuel type, and age of the source. Tune up costs are generally estimated by companies using an estimate of man-hours required to complete the work considering the cost per hour or day for qualified personnel. Additional costs a facility will incur will include on-site personnel time allotted to coordinate on-site contractors as well as administrative costs for the preparation and maintenance of the proposed annual tune-up report. Highly specialized fuel burning equipment will require more experienced personnel or contractors, which also impact costs. Although very small units may take as little as one day to complete a tune-up, larger more complex sources can require a two or three man team, which can span more than three weeks for an initial tune-up and up to two weeks for an annual tune-up. This could result in tune-up costs up to $36,000 for an initial tune-up and up to $12,000 for the annual tune-up depending upon the number of burners (30 to 50 burners may be present), as well as the size and configuration of the combustion system.
It should be noted that in EPA's assessment that it is assumed that all burners are accessible for inspection and that there are no costs associated with BPH shutdowns to allow inspection. Due to the site-specific nature of these impacts, Trinity was also unable to readily develop cost impacts estimates; however, such cost impacts would likely be significant.

Response: EPA thanks the commenter for communicating the results of the survey of contractors specializing in tune ups. In its final cost analysis EPA estimated the purchased technical cost of the tune-up using available technical literature prepared by the Industrial Extension Service USI boiler Efficiency Program. It is unknown what fraction of units would need to install replacement burner components as a result of the findings of the tune-up and so EPA did not estimate those costs. EPA also included in its ICR burden estimate time for the facility to submit and prepare records and the annual or biennial tune-up report, although these costs are not included in the purchase price of the tune-up. Further, many other commenters indicate that affected facilities are already conducing routine tune-ups, and presumably these units would be replacing broken components identified during the tune-up in order to maintain efficient combustion. Since many facilities are already undergoing the cost of routine tune-up preparation and implementation and will not experience significant additional costs to complete the same activity now required under the final rule, EPA disagrees that it has underestimated the costs of the tune-up.

Commenter Name: Matthew Todd and David Friedman

Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 308

Comment: This section presents revised cost estimates for tune-ups of gas-fired boilers and process heaters. Costs for both the initial and annual boiler and process heater tune-ups were obtained from boiler service contractors without adding additional costs associated with facility personnel oversight of the boiler tune-up program. The estimates also do not consider the added cost for replacing burner components.

The revised costs included in this section of the report are based on a survey of the following resources:
* Alstom Power, Monroeville, PA
* B & W Inc, Hummelstown, PA
* Corval Group, Atwater, MN
* Delval, Washington PA
* Devco Process Heaters, Tulsa OK
* Energy Control, Broadview Heights, OH
* Exotherm Process heaters, Houston, TX
* Kasco Boiler Repair Golden, CO
* North Carolina State University, Mechanical & Aerospace Engineering, Industrial Extension Service
* Servco Industrial Equipment, Salt Lake City, UT
* Tate Engineering, Baltimore, MD
* The G. C. Broach Company, Tulsa, OK

Based on feedback from a survey of a number of contractors specializing in tune ups, costs are generally dependent upon the heat input capacity of the combustion system. Accordingly, Trinity estimated total costs by multiplying vendor-estimated costs for certain heat input capacities by the population of units estimated by EPA in that category. In order to maintain consistency with EPA's calculations, the costs for the initial tune-up have been annualized over a 5 year period at 7% interest. Table 7-1 and Table 7-2 show annual costs estimated for Gas 1 and Gas 2 subcategories, respectively.

[See submittal for TABLE 7-1. ANNUAL COSTS FOR GAS 1 UNIT TUNE-UPS ($)]

[See submittal for TABLE 7-2. ANNUAL COSTS FOR GAS 2 UNIT TUNE-UPS ($)]

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2960.1, excerpt 307 for a response to tune-ups cost estimates.

Commenter Name: David Bonistall
Commenter Affiliation: NewPage Corp

Document Control Number: EPA-HQ-OAR-2002-0058-2920.1
Comment Excerpt Number: 24

Comment: While we agree and support EPA's assessment of the Gas 1 subcategory and support the proposed work practices, we do have concerns with having a requirement to conduct annual boiler tune-up. We have natural gas-fired units that do not run frequently as they are ancillary or backup equipment, but do not contain any limitations on use in the event the "primary" unit is down for maintenance or repairs. When facilities have this redundancy, these ancillary units may only run for a limited number of hours during a calendar year. Having to conduct an annual tune-up on a boiler that may not have run during the past year or may have run for only a limited number of hours is not the best use of financial and technical resources. In order to minimize financial impact of the rule to facilities and to free-up limited technical boiler resources, we are suggesting EPA adopt an hours of operation interpretation rather than an annual requirement for these ancillary units. Our suggestion is for EPA to establish a subcategory for Gas 1 ancillary units where these units need to conduct a tune-up every 4000 hours of operation or five years whichever comes first.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2761.1, excerpt 4 for a response to tune-up frequency for limited use combustors.

Commenter Name: Eric Trauner
Commenter Affiliation: Citizen
Document Control Number: EPA-HQ-OAR-2002-0058-2768
Comment Excerpt Number: 2

Comment: Regarding tune-up expectations, more clarification is needed on methods to be used when assessing exhaust gases for CO content, and more clarity is needed on expectations for such a periodic report.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-3137.1, excerpt 36 for a response to handheld instruments.

Commenter Name: Ken Wiegand
Commenter Affiliation: Denison University
Document Control Number: EPA-HQ-OAR-2002-0058-2834.1
Comment Excerpt Number: 2

Comment: The proposed approach to regulating boilers in the "Gas 1" subcategory should be based on actual operational hours and not on an annual or biannual basis, depending on the size of the unit.

Instead of prescribing numeric HAP emissions limitations on boilers burning clean gas fuels (the "Gas 1" subcategory), EPA proposes to adopt work practices requiring an annual tune up of boilers with heat input capacity of greater than 10 million BTU per hour and a biannual tune up of boilers with heat input capacity of less than 10 million BTU per hour. Tuning a boiler based on a random time frequency without regard to actual operating hours serves no logical purpose. The frequency of boiler tuning should be based on operational hours. Potential to Emit (PTE) analysis are based on 8760 hours of operation, which is the equivalent of operating for 24 hours a day, seven days a week and 52 weeks a year. Denison University's gas boilers only operate a few weeks a year or less. Since PTE analysis are used as a basis for State Implementation Plans, and Title V Permitting, it would be logical to use 8760 hours of operation as a frequency for burner tuning, of boilers with heat input capacity of greater than 10 million BTU per hour. Burner tuning of boilers with heat input capacity of less than 10 million BTU per hour at a major source facility would be quite expensive for numerous small boilers. The use of 8760 hours of operation fits in the regulatory framework already put in place by USEPA.

EPA proposes that work practice standards are appropriate and justified for units in the Gas 1 subcategory out of concern for the cost of complying with numeric emissions limitations and based on the adverse policy incentives that would be created. The proposed work practices should be based on 8760 operating hours, for boilers having heat input capacity greater than 10 million BTU per hour. For boilers with heat input capacity of less than 10 million BTU per hour, the cost of burner tuning does not justify the expense and resulting environmental benefit.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2761.1, excerpt 4 for a response to tune-up frequency for limited use combustors.

Commenter Name: Tom Siegrist
Commenter Affiliation: Koch Nitrogen Company, LLC
Document Control Number: EPA-HQ-OAR-2002-0058-3127
Comment Excerpt Number: 3

Comment: Proposed requirements of the Work Practice Standard (Subpart DDDDD, Table 3, 75 FR 32068) should be modified in recognition of standard industry practice regarding scheduled maintenance turn-arounds, state-specific boiler inspection requirements, and safety concerns.

KNC operates boilers and process heaters in chemical manufacturing processes that can have periods of operation that extend for several years. On a regular basis and consistent with process safety regulations, standards, and good operating practices, these units are inspected and any required preventative maintenance is performed during a scheduled turn-around at the end of the extended operating period. The proposed annual tune-up requirement would result in a facility taking a boiler or process heater, along with the associated production unit, out of service in order to complete the annual tune-up. The additional startups and shutdowns could result in increased emissions from the facility, decreased energy efficiency, and increased worker safety concerns. In order to avoid these unintended consequences, KNC proposes the following modification to 63.7540(a)(10):

If you boiler or process heater is in either the Gas 1 (NG/RG) or Metal Process Furnace subcategories and has a heat input capacity of 10 million Btu per hour or greater, you must conduct a tune-up of the boiler or process heater in each calendar year in which the unit operates, or at the next scheduled maintenance turn-around, to demonstrate continuous compliance as specified in paragraphs (a)(10)(i) through (a)(10)(vi) of this section.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-3213.1, excerpt 112 for a response to tune-up requirements.

Commenter Name: Robert P. Strieter
Commenter Affiliation: The Aluminum Association
Document Control Number: EPA-HQ-OAR-2002-0058-2711.1
Comment Excerpt Number: 5

Comment: The proposed rule specifies Work Practice Requirements for the Metal Process Furnace subcategory. The Aluminum Association supports Work Practices for insuring emissions performance through proper burner maintenance (i.e., burner tune-ups). However, we disagree with the proposed rule requirement to install a natural gas meter on each furnace [§63.7540(a)(10)(vi)(C). Installation of natural gas meters will provide no useful information regarding burner performance because Metal Process Furnaces operate differently (cycle length, temperature and number) in any given 12-month period. Gas usage over 12 months is therefore not directly related to burner emissions performance or tune-ups. EPA should delete this requirement from the proposed rule.

Response: EPA has modified the final rule requirements to minimize the requirements for new individual gas meters at small units. In the final rule, units sharing a common fuel meter can use a common fuel meter to meet the requirement for measuring fuel consumption.

Commenter Name: John Hopewell
Commenter Affiliation: American Coatings Association
Document Control Number: EPA-HQ-OAR-2002-0058-2886.1
Comment Excerpt Number: 6

Comment: ACA supports the inclusion of work practices

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2938.1, excerpt 1 for a response the inclusion of work practices.

Commenter Name: Pamela F. Faggert

Commenter Affiliation: Dominion
Document Control Number: EPA-HQ-OAR-2002-0058-2908.1
Comment Excerpt Number: 10

Comment: EPA should provide additional flexibility and/or alternatives to the proposed tune-up requirements. EPA should allow the option for operator-defined procedures rather than sole reliance on manufacturer's specifications.
EPA should provide clarification that CO measurements for tune-ups are not related to any CO emission standard in the rule.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2761.1, excerpt 5 for a response to flexibility with respect to manufacturer's specifications and tune-ups.

Commenter Name: Cathy S. Woollums
Commenter Affiliation: MidAmerican Energy Holdings Company
Document Control Number: EPA-HQ-OAR-2002-0058-2786.1
Comment Excerpt Number: 14

Comment: MidAmerican Questions the Need for Work Practice Standards for Units with Capacity under 10 million Btu Per Hour. MidAmerican submits that it is both unnecessary and impractical for the EPA to require Work Practice Standards for small boilers and process heaters (under 10 million Btu per hour). MidAmerican and all regulated entities with these smaller units have an economic incentive to guarantee optimal performance. Optimal performance will result in lower fuel input costs. The EPA does not need to prescribe the frequency of regular tune ups for these units. Further, to the extent that redundant, backup, and/or emergency equipment is not utilized, requiring annual tune-ups imposes significant and unnecessary costs.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2960.1, excerpt 70 for a response to the tune-up exemption for small capacity units.

Commenter Name: Cathy S. Woollums
Commenter Affiliation: MidAmerican Energy Holdings Company
Document Control Number: EPA-HQ-OAR-2002-0058-2786.1
Comment Excerpt Number: 15

Comment: Further, for many smaller units physical or operational adjustments of the burner cannot be performed. As one example, line heaters, once set up per the manufacturer's specifications and performance tested by the manufacturer, are maintenance free. These units have several alarms; if the operating temperature drops below the set point, the unit will shut down. However, there are no adjustments that can be made to these heaters. There is a very narrow operating range for many of these small boilers/process heaters. Field experience by MidAmerican technicians has demonstrated that adjustments to the air/fuel ratio for small heaters (less than 1 mmBtu/hour) are operationally difficult to make and such minor adjustments have caused the burners to fail to stay lit.

Response: In order to avoid finalizing requirements that cannot practically be met, EPA has adjusted the language to indicate “as applicable” for many of the tune-up requirements.

Commenter Name: J. Michael Geers
Commenter Affiliation: Duke Energy
Document Control Number: EPA-HQ-OAR-2002-0058-2765.1
Comment Excerpt Number: 15

Comment: EPA’s Requirement for an Annual Tune-Up is Inconsistent With the Operational Practices of Some Industrial Boilers
In the Continuous Compliance Requirements of 63.7540, EPA proposes to require that certain source categories perform an annual tune-up. EPA should recognize that some sources

are routinely operated continuously for long periods at a time and do not schedule a yearly routine maintenance outage. Since conducting a tune-up requires inspection and maintenance of internal components, the unit must be shut-down. An annual tune-up in some cases would therefore force the shutdown of a unit at a potentially significant economic loss to the owner. To prevent this situation, EPA should allow a source the ability to seek a waiver or extension from the local permitting agency to allow sources to perform a tune-up on a less frequent basis that fits with the source’s operations.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-3213.1, excerpt 112 for a response to tune-up requirements.

Commenter Name: Cathy S. Woollums
Commenter Affiliation: MidAmerican Energy Holdings Company
Document Control Number: EPA-HQ-OAR-2002-0058-2786.1
Comment Excerpt Number: 16

Comment: MidAmerican also questions the proposed Work Practice Standard to measure fuel consumption. This requirement would be costly since most of these smaller units do not currently have a dedicated fuel gauge/meter. It is estimated that the labor and capital to install a meter would be about $5,000 per unit. Measurement of fuel consumption will not lead to lower emissions; there are numerous other variables that impact efficiency and, resultingly, emissions. If the fuel consumption increases or decreases, the temperature will stray and the unit will automatically shut down. Since the typical HAP emission from a heater of this size is less than 1 pound per year, the capital expenditure associated with fuel consumption is excessive compared to any real HAP emission reductions.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2711.1, excerpt 5 for a response to handheld instruments.

Commenter Name: John Hopewell
Commenter Affiliation: American Coatings Association
Document Control Number: EPA-HQ-OAR-2002-0058-2886.1
Comment Excerpt Number: 21

Comment: Tune-up requirements should be revised.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2960.1, excerpt 71 for a response to underestimated tune-up costs.

Commenter Name: Russ A. Wozniak
Commenter Affiliation: Dow Chemical Company
Document Control Number: EPA-HQ-OAR-2002-0058-2632.1
Comment Excerpt Number: 44

Comment: Changes are Needed to the Annual Tune Up Requirements for Boilers and Process Heaters. The proposed requirements in 63.7515(e) to conduct annual performance tune-ups must not be stipulated in the rule. All boilers and process heaters undergo maintenance and preventive maintenance procedures as recommended by the manufacturers or by industry practice. Some of these units may not require annual tune-ups, and conducting annual tune-ups may not increase the performance of these units due to design and operating conditions. In addition, some tune-ups may require shutdowns and many units operate continuously for years before they are shutdown for scheduled maintenance.

In addition, some boiler preventative maintenance is coordinated with state inspections. Frequency of state inspections varies by state but can be 12 to 24 months. In these instances the rule must allow tune-ups to be coordinated with state inspections.

Therefore, the rule should be revised to require each affected unit to have a written tune- up schedule based on the manufacturer’s recommendation or industry practice and conduct tune-ups according to the written schedule.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-3213.1, excerpt 112 for a response to tune-up requirements.

Commenter Name: Russ A. Wozniak
Commenter Affiliation: Dow Chemical Company

Document Control Number: EPA-HQ-OAR-2002-0058-2632.1
Comment Excerpt Number: 45

Comment: The proposed work practice requirements in 63.7540(a)(10) where measurement of CO concentration in the effluent stream before and after tune-up adjustments are made is excessive and should be deleted from the rule. There is no reason to require CO measurements where there are no CO emission standards to meet. This requirement may force facilities to conduct stack testing or CO measurements with no environmental benefit at considerable costs and effort. Due to these reasons, at a minimum, the CO measurement requirement must be deleted from the rule.

Response: EPA disagrees. The CO measurements can be done with handheld monitors that should add little expense to a tune-up program.

Commenter Name: Jerry Osheka
Commenter Affiliation: PPG Industries
Document Control Number: EPA-HQ-OAR-2002-0058-2938.1
Comment Excerpt Number: 1

Comment: PPG Supports the Inclusion of Work Practices as the MACT Floor for Gas 1 Fuels. Instead of prescribing numeric HAP emissions limitations on boilers burning clean gas fuels (the "Gas 1" subcategory), EPA proposes to adopt work practices requiring an annual tune up of the boiler.

PPG strongly supports EPA's proposal to establish annual tune-ups as the MACT standard for existing and new Gas 1 boilers and process heaters, and respectfully urges EPA to adopt that proposal in final form, rejecting any comments urging the adoption of numerical emission limits, such as those on which EPA solicited comment. In adopting annual tune-ups as MACT, EPA should recognize expressly that they constitute the floor for existing and new Gas 1 boilers and process heaters and that no beyond-the-floor requirement would be appropriate for the reasons EPA gave in support of its proposal, namely: the exorbitant cost of compliance and the perverse incentives.

Response: In the final rule EPA is retained the tune-up quiring a work practice standard for the gas 1 subcategory. See the preamble for justification of the work practice standards and the classes of boilers and process heaters that are eligible for the tune-up in the final rule.

Commenter Name: Floyd DesChamps
Commenter Affiliation: Alliance to Save Energy
Document Control Number: EPA-HQ-OAR-2002-0058-2921.1
Comment Excerpt Number: 1

Comment: We support inclusion of a biennial boiler tune-up requirement in the rule for applicable small (less than 10 million Btu input per hour) boilers as a means to enhance combustion efficiency and reduce HAP emissions. We suggest clarification as to whether the proposed rule would require tune-up solely of the combustion systems of boilers or of the entire boiler (or furnace) system (e.g., feedwater system, instruments, draft fan). We recommend the broader form of tune-up, which would allow additional efficiency measures to be addressed beyond combustion control.

Response: We appreciate the support of the biennial tune-up requirement. The final rule clarifies the requirements for the tune-up see §63.7540(a)(10). It should be noted that existing facilities are also subject to an energy assessment which is more comprehensive.

Commenter Name: Tom Brotherman
Commenter Affiliation: CPS Energy
Document Control Number: EPA-HQ-OAR-2002-0058-3138
Comment Excerpt Number: 2

Comment: We believe the work practice standards are a good idea. However, because of the low amount of hours per year our process heaters operate, we would like to see annual tune-up and testing be changed from an annual basis to a minimum/maximum amount of hours and/or maximum elapsed time. We are suggesting that the tune-1 and emissions testing be required between 7,300 and 8,760 operating hours or before the 5’ anniversary of the previous tune-up.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2761.1, excerpt 4 for a response to tune-up frequency for limited use combustors.

Commenter Name: Frederick R. Albrecht
Commenter Affiliation: SCA Tissue
Document Control Number: EPA-HQ-OAR-2002-0058-2843.1
Comment Excerpt Number: 2

Comment: In the area of Work Practices, the EPA rules are focused on CO reduction. SCA is focused on CO_2 reduction and has aggressive targets for this across the US and across our global operations. However, the EPA’s strong focus on reduction of CO emissions could have the unintended impact of increasing manufacturers’ emissions of other pollutants. For instance, a business could reduce its CO emissions by increasing its emissions of NOx. Clearly this would not be a desired outcome nor the intent of the EPA’s rule.
We recommend that the rules be modified to read: ‘Minimize total emissions of CO consistent with the manufacturer’s specifications while also assuring compliance with total emissions of other regulated pollutants."

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2506.1, excerpt 13 for a response the consequences of minimizing CO.

Commenter Name: Gregory A. Wilkins
Commenter Affiliation: Marathon Petroleum Company
Document Control Number: EPA-HQ-OAR-2002-0058-3119.1
Comment Excerpt Number: 3

Comment: Because EPA's current proposed approach has the unintended consequence of requiring inefficient operation of fired equipment (resulting in more fuel consumed than is optimal) Marathon recommends that the CO standards be adjusted so that equipment can be operated for optimal energy efficiency during all period of normal operation, including turndown. While optimal CO levels are generally no more than 400 ppmv, excess oxygen is added to assure safe operation of fired equipment to account for changes in process heat needs, fuel composition and other variables. HAP emissions are negligible with little change between these low CO levels and EPA's proposed standard. Finalizing more appropriate CO standards and work practices will result in less fuel consumption and fewer emissions.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2506.1, excerpt 13 for a response the consequences of minimizing CO.

Commenter Name: Chris Welch
Commenter Affiliation: Colorado Springs Utilities
Document Control Number: EPA-HQ-OAR-2002-0058-2943.1
Comment Excerpt Number: 4

Comment: Within the proposed rule, a six step tune up procedure is outlined. Currently CSU performs maintenance that includes many of these procedures on our sealed facility boilers used for comfort heat. These units optimize C02 and 02 through intemal controls. However, some of our boilers are equipped with atmospheric bumers though, there is little adjustment that can be made, and not all of the outlined tune-up steps are applicable. This would not be an issue if instead the manufacturer recommended tune-up procedures were referenced.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2761.1, excerpt 5 for a response to flexibility with respect to manufacturer's specifications and tune-ups.

Commenter Name: Bethany J. Johnson
Commenter Affiliation: The Boeing Company
Document Control Number: EPA-HQ-OAR-2002-0058-2894.1
Comment Excerpt Number: 5

Comment: Clarify that Before and After Tune-up CO Measurement Does Not Require a formal "Performance Stack Test"
40 CFR 63.7540(a)(vi)(A) requires that concentrations of CO in the effluent stream be measured before and after the tune-up adjustments. We request EPA clarification that the measurement of CO before and after tune-ups is not considered a "performance test" and therefore the measurement does not have to be performed according to the test methods or procedures specified in Table 5 of the rule. This would allow us to use inexpensive handheld CO and humidity probes instead of having to hire a vendor to perform a stack test, while still providing adequate data for purposes of evaluating the effects of tune-up adjustments.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-3137.1, excerpt 36 for a response to handheld instruments.

Commenter Name: William C. Herz
Commenter Affiliation: The Fertilizer Institute
Document Control Number: EPA-HQ-OAR-2002-0058-2874.1
Comment Excerpt Number: 5

Comment: TFI is concerned about the feasibility of conducting annual tune-ups while operating process units. For most chemical facilities, inspecting the burner requires shutdown of the boiler itself and the associated chemical process unit. Required shutdowns result in emissions of pollutants above normal operating conditions. Shut downs also negatively impact plant efficiency as combustion of additional natural gas is required to shut down and restart the process unit. In cases where multiple burners are fired, pulling one burner while the others remain in service presents a significant safety hazard to the personnel pulling the burner.

TFI requests that the requirement for annual shut downs of chemical facilities for tune-ups be removed, given that it may decrease energy efficiency, increase environmental emissions, and increase worker safety risks. This is counter to the intent of the Major Source Boiler rule.
The environmental performance of the boiler can be detected by other inherently safer means. For natural gas fired sources, visual inspection of the flame pattern combined with CO and O2 concentration measurements are safer, non-intrusive indicators of burner performance.
TFI recommends that burner performance be evaluated while the reformer is operating. Requiring removal of the burner for inspection and cleaning is more prudent when conditions dictate, i.e. poor burner performance is detected due to poor flame patterns and overall CO concentrations.

Response: EPA has adjusted several provisions of the tune-up in the final rule in order to accommodate operational flexibilities. As long as owners/operators complete the parts of the tune-up that can be completed, they can postpone impractical requirements until the next scheduled outage.

Commenter Name: William C. Herz
Commenter Affiliation: The Fertilizer Institute
Document Control Number: EPA-HQ-OAR-2002-0058-2874.1
Comment Excerpt Number: 6

Comment: All ASME Section 1 boilers are required to be inspected within five years from the date of the last inspection. This boiler inspection interval is consistent with preventive maintenance inspections of other equipment and catalyst life in a process unit. Requiring the full work practice standard within the same time interval as the ASME Section 1 boiler inspection would provide a more efficient and safe alternative while not sacrificing targeted emission limits.

TFI requests that EPA specify tune-up frequencies based upon standard industry practice regarding scheduled turn-arounds or a frequency consistent with state-specific boiler inspection requirements, such as the five-year interval for ASME Section 1 boilers. Other less intrusive portions of the requirements (e.g., inspecting air-to-fuel ratio, adjusting flame patterns, other manufacturer requirements) are already performed on an as-needed basis, and should be required to be recorded as completed rather than forcing an annual shut down of a process unit.

Response: We have not adjusted the tune-up frequency in the final rule. The commenter did not provide sufficient justification that tune-ups conducted less frequently will have the same impact on emissions as the schedule contained in the final rule. Further, technical literature provided by a Sustainable Energy Authority in Ireland provide graphs relating the time lapse since a previous tune-up with incremental improvement in fuel efficiency. In the final rule we have allowed limited exceptions to the biennial/annual frequency for units that supply process heat or steam to long term processes. These exceptions allow units to delay the more intrusive portions of the tune-up until the next scheduled shutdown. See preamble for justification of the work practice standards retained in the final rule.

Commenter Name: William C. Herz
Commenter Affiliation: The Fertilizer Institute
Document Control Number: EPA-HQ-OAR-2002-0058-2874.1
Comment Excerpt Number: 7

Comment: For an ammonia plant reformer which may incorporate over one hundred burners in the same furnace, inspection of the burner performance is essential to ensure proper heat distribution in the catalyst tubes. Slight adjustments are frequently made not only to ensure cleanliness of the burner gun but also to correct the direction of firing based on heat distribution to surrounding tubes. Failure to perform these inspections can lead to failure of a catalyst tube, safety risk of tube rupture in the furnace, extended down time required for repair, and economic penalty caused from the loss production and combustion of natural gas during shut down and start up.

TFI requests that EPA exempt ammonia plant reformers from the requirement to remove and inspect burners since standard industry practice is to inspect burners for proper performance to prevent catastrophic failure of catalyst tubes during normal operation. Other less intrusive portions of the requirements (e.g., inspecting air-to-fuel ratio, adjusting flame patters, other manufacturer requirements) are already performed on an as-needed basis, and should berequired to be recorded as completed rather than forcing removal of the many burners in an ammonia reformer.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2874.1, excerpt 5 for a response to tune-ups requirements for ammonia plants.

Commenter Name: Sarah E. Amick
Commenter Affiliation: Rubber Manufacturers Association
Document Control Number: EPA-HQ-OAR-2002-0058-2941.1
Comment Excerpt Number: 7

Comment: Annual tune-ups intended to minimize CO emissions are proposed for existing boilers and process heaters with a design heat duty of >10 MMBTU/hr that fire Gas 1. Biennial tune-ups are required for units with a design heat input <10 MMBTU/hr regardless of what type of gas they combust. RMA does not believe that such tune-ups are MACT, as EPA claims in the proposal preamble.

The basis for EPA's conclusion that a tune-up for minimizing CO constitutes the MACT floor is the claim that many States require tune-ups. While this is correct to some extent, these State tune-ups typically are for the purpose of minimizing NOx or optimizing combustion by minimizing O2 and do not require minimizing CO as EPA proposes. In fact, reducing CO using the tune-up procedure EPA proposes would violate the very tune-up requirements EPA cites, because reducing CO increases NOx and requires increasing O2. Furthermore, it is not clear that the proposed tune-up would reduce any annual emissions, since the tune-up itself raises emissions while it is being done. Thus, while we believe a simple, non invasive inspection work practice might add some value and meet the requirements of §112, the proposal to use the tune-up to minimize CO emissions should not be finalized as presented.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2506.1, excerpt 13 for a response the consequences of minimizing CO.

Commenter Name: William O'Sullivan
Commenter Affiliation: New Jersey Department of Environmental Protection
Document Control Number: EPA-HQ-OAR-2002-0058-2969.1
Comment Excerpt Number: 8

Comment: We support the proposed tune up work practice standard for those sources that do not have emission limits. Since NOx emissions can increase with decreases in CO emissions, we recommend that tune up is done to minimize total emissions of NO and CO consistent with the manufacturer’s specifications.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2506.1, excerpt 13 for a response the consequences of minimizing CO.

Commenter Name: Dan F. Hunter
Commenter Affiliation: ConocoPhillips Company
Document Control Number: EPA-HQ-OAR-2002-0058-2867.1
Comment Excerpt Number: 9

Comment: Basing the tune-ups on CO emissions will be in general opposition to existing state rules targeting NOx reduction and tune-ups as recommended by boiler and process heater manufacturers. Critical safety issues associated with tuning and ongoing operation of combustion units must be considered. Since the goal of tune-ups is the minimization of fuel use and mass emissions through efficient unit operation, existing state rules requiring boiler or heater tune-ups should be deemed appropriate and equivalent work practices.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2506.1, excerpt 13 for a response the consequences of minimizing CO.

Commenter Name: John M. Irving
Commenter Affiliation: Burlington Electric Department
Document Control Number: EPA-HQ-OAR-2002-0058-2954.1
Comment Excerpt Number: 9

Comment: Work practice standards are typically operating measures all sources do to reduce fuel consumption and improve efficiency. Regulating work practices does not make the results better.

Response: While some boilers may routinely performed tune-ups, according to the ICR survey, there is still a large percent that do not. EPA expects a reduction in the overall national emissions will result from tune-ups.

Commenter Name: William O'Sullivan
Commenter Affiliation: New Jersey Department of Environmental Protection
Document Control Number: EPA-HQ-OAR-2002-0058-2969.1
Comment Excerpt Number: 9

Comment: .

We recommend that USEPA include a provision that the
adjusted equipment is maintained to operate consistent with the annual adjustment. NJDEP has adopted RACY rules to require annual NO and CO testing, with adjustment of combustion process for boilers greater than 5 million BTU/hr.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2875.1, excerpt 11 for a response to using a CO CEMS to ensure compliance with the "good tuning".

Commenter Name: Alicia Oman
Commenter Affiliation: National Association of Manufacturers
Document Control Number: EPA-HQ-OAR-2002-0058-2845.1
Comment Excerpt Number: 10

Comment: EPA should require only a one time tune-up for smaller boilers and process heaters.

Manufacturers recommends that EPA require only a one time tune-up for smaller boilers and process heaters with rated heat input less than 2 million British Thermal Units (BTUs). Currently, both the South Coast Air Quality Management District and Antelope Valley Air Quality Management District exempt boilers and process heaters with a rated heat input less than or equal to 2 million BTUs per hour from having their burners tuned. Because of the small size of these units, the cost burden of regular tune-ups far outweighs any environmental benefit that may be achieved.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2960.1, excerpt 70 for a response to the tune-up exemption for small capacity units.

Commenter Name: Richard Krock
Commenter Affiliation: The Vinyl Institute
Document Control Number: EPA-HQ-OAR-2002-0058-2944.1
Comment Excerpt Number: 12

Comment: Not all boilers and few process heaters can be readily shutdown. Inspection should be delayed until the unit can be shutdown without impact. For units such as process heaters that do not shut down for extended periods of time, scheduling flexibility must be provided so that tune-ups can be done in association with normal inspection and overhaul schedules. EPA should also reword the work practice requirements so that sources have flexibility to adapt procedures as applicable and appropriate for specific sources. In addition, the “tune-up” definition implies that use of an approved specialist could be required. EPA should recognize that many companies have in-house personnel who are already well qualified, and already perform adjustments to burner systems. Continued use of these in-house resources must be supported.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-3213.1, excerpt 112 for a response to tune-up requirements.

Commenter Name: Douglas J. Van Pelt
Commenter Affiliation: ExxonMobil
Document Control Number: EPA-HQ-OAR-2002-0058-2968.1
Comment Excerpt Number: 12

Comment: Unscheduled Shutdowns. As proposed in section 63.7540(a)(10)(i)-(iii) for tune-up activities, it may be necessary to shut down a boiler or process heater to perform these inspections. However, most boilers and process heaters cannot be readily shut down to perform a burner inspection as required by (a)(10)(i) and (ii), since burners are not always retractable and cannot always be inspected or cleaned with the boiler or process heater in service. Furthermore, many boilers operate with positive firebox pressures that would expose personnel to hazardous conditions for on-line inspections. In those cases where the boiler or process heater is not spared or cannot be shut down without impacting steam or process heat consumers, this requirement should allow for delaying the burner inspection until the unit can be shut down without impact. Potential unit and process shutdowns were not considered in evaluating the tune-up emissions impacts, costs or burdens and are not justified.

Clarify that boiler and process heaters need not shut down to accomplish the required inspections or to clean burners, or allow the inspections to occur with planned maintenance downtimes of these sources.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-3213.1, excerpt 112 for a response to scheduling of tune-ups.

Commenter Name: Richard Rosvold
Commenter Affiliation: Xcel Energy Services, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2955.1
Comment Excerpt Number: 13

Comment: Annual/biennial tune ups are excessive, especially for liquid- and gas-fired boilers with low hours of operation. These units burn relatively cleanly and generally do not become "out of tune" this quickly. We suggest a tune up frequency of once every five years for units burning distillate oil, biodiesel, and gaseous fuels, or that the tune-up frequency be based on hours of operation of the unit.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2761.1, excerpt 4 for a response to tune-up frequency for limited use combustors.

Commenter Name: Edward E. Quick
Commenter Affiliation: Celanese International Corp
Document Control Number: EPA-HQ-OAR-2002-0058-2840.1
Comment Excerpt Number: 21

Comment: Celanese agrees in general that work practice standards such as boiler inspections and tune-ups are appropriate for smaller boilers and those fired by natural gas. We disagree with the tune-up requirements to: "Minimize total emissions of CO consistent with the manufacturer's specifications; Measure the concentration in the effluent stream of CO in parts per million, by volume, dry basis (ppmvd), before and after the adjustments are made..."

Tuning boilers to reduce CO emissions often results in a trade off between CO and NOx emissions. In many cases, the lowest possible CO emission rate is achieved by increasing excess air and flame temperature. These conditions decrease boiler and process heater efficiency, and also increase emissions of other pollutants, such as NOx and greenhouse gases. We therefore recommend that these two requirements under the work practice standard be removed from the final regulation.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2506.1, excerpt 13 for a response the consequences of minimizing CO.

Commenter Name: Christopher S. Colman
Commenter Affiliation: Hovensa LLC
Document Control Number: EPA-HQ-OAR-2002-0058-2863.1
Comment Excerpt Number: 49

Comment: Proposed Rule Language §63.7540(a)(10)(v):
"Measure the concentration in the effluent stream of CO in parts per million, by volume, dry basis (ppmvd), before and after the adjustments are made; and."
Comments:
Section §63.7540(a)(10)(v) indicates that the CO concentration in the effluent stream must be measured before and after the required adjustments are made. However, Section 63.7540 does not specify the method or equipment required to take this measurement. This section should be revised to clarify to include the required measurement methodology and equipment. A handheld portable equipment should be sufficient to conduct tune-up adjustments.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-3137.1, excerpt 36 for a response to handheld instruments.

Commenter Name: Traylor Champion
Commenter Affiliation: Georgia-Pacific LLC

Document Control Number: EPA-HQ-OAR-2002-0058-2745.1
Comment Excerpt Number: 65

Comment: Boiler tune up procedures for natural gas boilers would require CO testing to measure the effectiveness of the tune up. However the proposed rule does not specify the procedures that must be used for this test. CO measurements for the tune up need not be conducted with the rigor of EPA Method 10 or 10A since the results are not used for compliance demonstration – only as an indication of a process improvement. There are several hand-held CO monitors that can be accurately and effectively used for this purpose by plant personnel instead of hiring an outside testing contractor.
GP urges EPA to clarify in the final rule that CO testing during an energy audit does not need to be done by EPA stack testing methods, but can be performed using commercially available portable CO analyzers.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-3137.1, excerpt 36 for a response to handheld instruments.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 199

Comment: EPA SHOULD REVISE THE TUNE-UP REQUIREMENTS. Proposed section 63.7540(a)(10) contains the specific tune-up work practice requirements for existing boilers and process heaters. We have the following comments on the specifics of the proposed tune-up work practice. ACC believes proposed section 63.7540(a)(10)(i)-(iii) reflect typical tune-up activities. Many jurisdictions require annual boiler inspections for safety reasons and boilers are often spared or can be shutdown when weather conditions are mild. Some jurisdictions require such inspections for process heaters, particularly as part of a NOx minimization effort.

However, not all boilers and few process heaters can be readily shutdown. The proposed (a)(10)(i) and (ii) burner inspections could require such a shutdown, since burners are not always retractable and cannot always be inspected or cleaned with the process heater in service. In those cases where the boiler or process heater is not spared or cannot be shutdown without impacting steam or process heat consumers this requirement should allow for delaying the burner inspection until the unit can be shutdown without impact. Potential unit and process shutdowns were not considered in evaluating the tune-up emissions impacts, costs or burdens and are not justified. EPA should clarify that boiler and process heaters need not shutdown to accomplish the required inspections or to clean burners. For units such as process heaters that do not shut down for extended periods of time, scheduling flexibility must be provided so that tune-ups can be done in association with normal inspection/overhaul schedules. For example, in the Mandatory Reporting Rule for GHG Emissions, EPA allows for postponing initial or subsequent calibrations until the next scheduled maintenance outage. [40 CFR 98.3(i)(6), 74 Fed. Reg. at 56381.] A similar approach should be used in the Boiler rule for scheduling of tune-ups on equipment which does not lend itself to an annual frequency.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-3213.1, excerpt 112 for a response to tune-up requirements.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 200

Comment: Proposed section 63.7540(a)(10)(iii) requires "Inspect the system controlling the air-to-fuel ratio, and ensure that it is correctly calibrated and functioning properly." This wording presumes an automatic air-to-fuel ratio controller, but those are present on a minority of process heaters. Where metered fuel/air control systems with O2 trim is installed, there is no real need for periodic "tune-ups" since combustion is continually optimized. Rather, burner/combustion system inspections, control equipment calibrations, and operational checks are all that should be needed to verify proper operation. EPA should reword the work practice requirements so that sources have flexibility to adapt procedures as most applicable and appropriate for specific sources.

Many units only have automatic draft control and individual, manual burner air control. For smaller units, draft control may be manual. Adding automatic air-to-fuel controls, as this requirement might be interpreted to require, is a very large, unjustified cost for units that do not have it, because it requires adding a forced draft combustion air system and perhaps an induced draft system. No such step was considered in the record and it is not justified.

EPA should reword proposed section 63.7540(a)(10)(iii) as follows:

"Inspect the draft control and burner air control systems to ensure they are operating properly. Inspect the system controlling the air-to-fuel ratio, if any, and ensure that it is correctly calibrated and functioning properly."

Response: Refer to DCN EPA-HQ-OAR-2002-0058-3213.1, excerpt 113 for a response to flexibility with respect to an air-to-fuel ratio controller.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 201

Comment: Proposed section 63.7540(a)(10)(iv) and (v) are not typical tune-up requirements for either boilers or process heaters and do not reflect MACT. State tune-up requirements require minimization of NOx, not CO. Thus, these subparagraphs do not reflect the state requirements and would violate the State tune-up requirements for minimizing NOx. Additionally, the tune-up requirement conflicts with the proposed energy assessment work practice requirements, because tuning a boiler or process heater for minimum CO generally requires increasing excess air, which increases energy consumption, in direct conflict with the energy assessment directive to decrease energy consumption.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2506.1, excerpt 13 for a response the consequences of minimizing CO.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 202

Comment: If the draft control on a boiler or process heater is working properly, as (a)(10)(iii) confirms, and there are no mechanical problems with the flame pattern, as (a)(10)(ii) confirms, there is no justification for measuring CO, since CO will be very low when these items are operating properly. Furthermore, these are elements typically checked and corrected if CO were high. Additionally, the mass of POM emissions that might be reduced from a gas fired boiler or process heater is insignificant.

EPA should remove the CO measurement requirements in the final rule. If they are not removed they must be justified, considering the NOx emissions increase they will engender and the rule must specifically address state requirements to minimize NOx. The O2 level in a boiler or process heater also must consider draft limitations, flame impingement, and flame stability to assure a safe, reliable and efficient operation, and these conditions are not recognized in the EPA tune-up procedure.

Response: EPA disagrees with the commenter. The requirement in the final rule is to optimize CO, rather than minimize, and the optimization can consider NOx.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 203

Comment: If burner/control adjustment relative to CO emissions is maintained in the tune-up procedure, the following changes are needed to reflect EPA’s description of this work practice, the Agency cost and burden estimate, to make the CO adjustment practical, and not to have it result in increased NOx and other emissions.

EPA should clarify the regulatory language that CO is only to be minimized to the extent the adjustments do not increase NOx emissions, decrease unit combustion efficiency, cause flame impingement or flame instability, or cause other safety issues, and that portable CO and O2 analyzers are acceptable, and that these tests are not performance tests. Further, it should be made clear that the tuning is to be done at a single representative operating rate. Neither the rulemaking record nor combustion principles justify multipoint tune-ups, especially when some units basically operate at a fixed rate.

For a short term adjustment situation, unit firing and stack conditions will not change enough for the stack moisture to vary significantly. Comparing CO measurements on either a wet or dry basis, before and after adjustment, is more than adequate to reflect the impact of adjustments.

The oxygen measurement should be specified to be based on either an O2 CEMS reading, if the unit has one, or measurement using a portable emissions monitor. It should be made clear that a Method 3 oxygen measurement is not required.

EPA should not finalize proposed section 63.7540(a)(10)(iv) and (v). If these requirements are maintained, they should be simplified and clarified as discussed in items 1-3, above and EPA must specifically over-ride State tune-up requirements to minimize NOx and/or O2.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2506.1, excerpt 13 for a response the consequences of minimizing CO. Refer to DCN EPA-HQ-OAR-2002-0058-3137.1, excerpt 36 for a response to handheld instruments. Refer to DCN EPA-HQ-OAR-2002-0058-2506.1, excerpt 14 for a response to efficiency across various load conditions.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 204

Comment: Proposed section 63.7515(e) requires that annual tune-ups be performed between 10 and 12 months after the previous tune-up. This means the tune-ups will be more frequent than on an annual basis, a fact not reflected in the record, and will make compliance difficult, because the source will not be able to do the tune-up at the same time each year. For instance if a tune-up is done in May one year, it must be done in April or May of the following year. Since good practice requires some allowance for problems and possible delay due to process operation issues, prudent sources will perform the tune-up in April. Then the next year's tune-up would be in March, etc. Under the proposed system, the work practice is actually required more frequently than annually, a fact not reflected in the record or cost analyses, and obviously not justified. We suggest section 63.7515 be revised to specify that annual tune-ups may be done at any time in the same calendar quarter as the initial tune-up was done, regardless of the particular month in which the tune-up occurred. If a boiler or process heater does not operate during the quarter, the tune-up should be required within 30 days after restart.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2960.1, excerpt 81 for a response to scheduling of tune-ups.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 205

Comment: The definition of "Tune-up" in the proposed rule correctly stipulates "optimize the combustion efficiency, whereas language noted above in section 63.7540(a)(10) requires "minimize total emissions of CO," which as noted above is an incorrect approach to a tune-up and will lead to lower efficiency and higher net total emissions. As indicated above, EPA needs to correct the language in section 63.7540. In addition, the "tune-up" definition implies that use of an approved specialist could be required. EPA needs to recognize that many companies have in-house resources who are already well qualified, and already do perform adjustments to burner systems. Continued use of these resources must be supported.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-3213.1, excerpt 117 for a response the definition of a tune-up. Refer to DCN EPA-HQ-OAR-2002-0058-2761.1, excerpt 5 for a response to flexibility with respect to manufacturer's specifications and tune-ups.

Other - Work Practices

Commenter Name: Jay C. Moon
Commenter Affiliation: Mississippi Manufacturers Association
Document Control Number: EPA-HQ-OAR-2002-0058-2690
Comment Excerpt Number: 4

Comment: EPA should also establish annual tune-up work practice as the MACT standard for biomass boilers. For example, in the forest products industry alone, the estimated cost of complying with the proposed HAP emissions limitations for biomass boilers is $3.3 billion. This is an extraordinary cost that, in the context of the forest products industry, equals or exceeds the magnitude of the economic burden that EPA predicts for the Gas 1 subcategory. Similarly severe economic impacts are expected in other industry sectors where biomass boilers are widely use, such as the furniture, sugar, and agricultural products industries. Thus, there is strong economic justification for prescribing work practice standards for biomass boilers in lieu of numeric emissions limitations.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2906.1, excerpt 5 for a response the request for work practices not emission limits.

Commenter Name: Richard T. Metcalf
Commenter Affiliation: Louisiana Mid-Continent Oil and Gas Association
Document Control Number: EPA-HQ-OAR-2002-0058-2699.1
Comment Excerpt Number: 1

Comment: A work practice for certain gas-fired units is appropriate, but should apply to all gas units.
The numeric emissions limits for gas-fired units in the rule will result in technically/practically infeasible standards and, from an energy efficiency standpoint, increased emissions by requiring non-optimal operating conditions. Natural gas, refinery fuel gas, and petrochemical fuel gas, often integrated in refinery fuel systems, have comparable composition and emission profiles and should be considered Gas 1 sources. .

Response: EPA has determined that to the extent that process gases are comparable to natural gas and refinery gas, combustion of those gases in boilers and process heaters should be subject to the same standards as combustion of natural gas and refinery gas. Therefore, we are providing a mechanism by which units that combust gaseous fuels other than natural gas and refinery gas can qualify as Gas 1 units and be subject to the standards for Gas 1 units.

EPA is providing a fuel specification that can be used by facilities to qualify Gas 2 units for the Gas 1 standards. The fuel specification would also allow facilities to perform precombustion gas cleanup in order to qualify Gas 2 units for the Gas 1 standards. For those process gases that do not meet the fuel specification and are not processed to meet the contaminant levels, we are finalizing emissions limits for Gas 2 units.

Commenter Name: Theresa Pugh
Commenter Affiliation: American Public Power Association
Document Control Number: EPA-HQ-OAR-2002-0058-2714.1
Comment Excerpt Number: 1

Comment: APPA supports the proposed rule’s treatment of natural gas-fired units and asks EPA to extend the work practice approach to landfill gas-fired boilers to eliminate any disincentive in the rule for public power communities to recover energy from this renewable energy source.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2906.1, excerpt 5 for a response the request for work practices not emission limits.

Commenter Name: Robert R. Scott
Commenter Affiliation: New Hampshire Department of Environmental Services, Air Resources Division
Document Control Number: EPA-HQ-OAR-2002-0058-2734.1
Comment Excerpt Number: 3

Comment: NHDES strongly supports adoption of timely final regulations in order to achieve the benefits to public health that will result from the regulations. In keeping with that desired outcome, we would recommend that EPA consider including provisions in the regulation that not only require effective emission limits for CO, but also a combustion efficiency component to ensure that combustion efficiency, and not just CO emission rates, be improved. NHDES would recommend that for existing units, EPA require annual tune-up and testing of combustion efficiency and for new units, EPA require that the manufacturer of the units certify that they meet efficiency standards along with an annual tune-up requirement.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2506.1, excerpt 13 for a response the consequences of minimizing CO.

Commenter Name: Jay C. Moon
Commenter Affiliation: Mississippi Manufacturers Association
Document Control Number: EPA-HQ-OAR-2002-0058-2690
Comment Excerpt Number: 3

Comment: EPA should, however, take the necessary next step and extend the work practice approach toall gas-fired units. Despite the exceedingly strict emissions limits that are proposed, EPA has not identified a demonstrated path to compliance for the remaining gas-fired units for which EPA has not proposed to make work practices available. Rather than imposing undue and unrealistic costs and standards on these remaining gas-fired boilers, EPA should allow work practices rather than require emissions limitations.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2699.1, excerpt 1 for a response to work practices for all gas units.

Commenter Name: James P. Brooks
Commenter Affiliation: Maine Department of Environmental Protection, Bureau of Air Quality
Document Control Number: EPA-HQ-OAR-2002-0058-2746.1
Comment Excerpt Number: 8

Comment: The U.S. Department of Energy regulates the efficiency of small “package” boilers in 10 CFR Part 431. This statute sets the efficiency for oil-fired hot water boilers between 300,000 Btu/hr and 2.5 MMBtu/hr at 82% thermal efficiency as of March 2, 2012; hot water boilers greater than 2.5 MMBtu/hr must have 84% combustion efficiency as of March 2, 2012.

Oil-fired steam boilers must have a thermal efficiency of 81% for both size categories as of March 2, 2012. Such combustion efficiencies effectively limit emissions of CO and other pollutants. We recommend that EPA adopt similar efficiency standards for new and existing boilers with capacities between 1 and 10 MMBtu/hr, and that EPA require a one-time energy audit.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2960.1, excerpt 70 for a response to the tune-up exemption for small capacity units.

Commenter Name: Richard T. Metcalf
Commenter Affiliation: Louisiana Mid-Continent Oil and Gas Association
Document Control Number: EPA-HQ-OAR-2002-0058-2699.1
Comment Excerpt Number: 8

Comment: Include additional fuel oil burning flexibility in the final rule. Work practice standards are more appropriate for fuel oil burning at refinery locations and remote locations without access to natural gas. If EPA decides to proceed to set HAP emission limits on refinery oil units, the ten-percent allowance needs to be made on the collection of heaters and boilers subject to the standards instead of the individual pieces of equipment.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2863.1, excerpt 37 for a response to work practices for remote locations.

Commenter Name: Lee Zeugin
Commenter Affiliation: Peabody Energy
Document Control Number: EPA-HQ-OAR-2002-0058-2730.1
Comment Excerpt Number: 8

Comment: Work Practice Standards Should Apply to All Gas-Fired Units. In the IB MACT rule, EPA has proposed to require existing boilers and process heaters burning either natural gas or refinery gas to meet a work practice standard rather than an emission limit. The work practice standard would require these units to conduct an annual tune up. See 75 Fed. Reg. 32,025. This work practice standard should be extended to IB units burning coal-derived gas.

The electric utility industry is increasingly being asked to consider constructing integrated gas combined cycle ("IGCC") units. These units include a coal gasifier that produces gas for later combustion in a gas turbine. The gas from an IGCC unit is cleaned prior to combustion so in terms of trace HAPs it is little different than natural gas or refinery gas.

Some coal-gasification processes include an additional methanation step that results in the production of synthetic natural gas ("SNG"). This product is indistinguishable from natural gas. Indeed, it qualifies for transport in natural gas pipelines. The proposed distinction between natural gas and other gas sources (like SNG) creates a compliance dilemma for end users. How does a natural gas user know if the gas from the pipeline that supplies its plant contains some amount of synthetic natural gas?

EPA's Gas 1/Gas 2 distinction is unworkable and all gas-fired IBs should be subject to work practice standards. If EPA keeps the distinction between gas sources, then it should, at a minimum, add coal-derived gas to the fuels in the Gas 1 category.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2699.1, excerpt 1 for a response to work practices for all gas units.

Commenter Name: Jack Carter
Commenter Affiliation: Weyerhaeuser Company
Document Control Number: EPA-HQ-OAR-2002-0058-2797.1
Comment Excerpt Number: 10

Comment: Rationales similar to those that support the proposed approach for the Gas-1 subcategory apply well to biomass boilers. As an AF&PA analysis demonstrates, in the forest products industry alone the estimated cost of complying with the proposed HAP emissions limitations for biomass boilers is $3.3 billion. For the forest products industry this is a cost burden of at least the same magnitude as that EPA estimates for the Gas-1 subcategory, and this level of severe economic impact is expected in the many other industry sectors where biomass boilers are widely used. Biomass is a relatively "clean" fuel relative to coal and other fossil fuels. Biomass-fired boilers typically have far lower HCl and Hg emissions than a comparable, well-controlled coal-fired boiler.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2906.1, excerpt 5 for a response the request for work practices not emission limits.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 107

Comment: The rationale that supports the proposed approach for the Gas 1 subcategory applies equally well to biomass boilers and, therefore, provides ample support for adopting alternative approaches such as the health-based alternatives, work practices instead of numeric emissions limitations, and otherwise considerably improved, reasonably established emissions limitations for biomass boilers. For example, in the forest products industry alone, the estimated cost of complying with the proposed HAP emissions limitations for biomass boilers is $3.3 billion. This is an extraordinary cost that, in the context of the forest products industry, equals or exceeds the magnitude of the economic burden that EPA predicts for the Gas 1 subcategory. Similarly severe economic impacts are expected in other industry sectors where biomass boilers are widely use, such as the furniture, sugar, and agricultural products industries. Thus, there is strong economic justification for prescribing work practice standards for biomass boilers in lieu of numeric emissions limitations.

In addition, biomass is a "clean" fuel in many of the same respects as the Gas 1 fuels. For example, a biomass-fired boiler typically will have far lower HCl and mercury emissions than a comparable, well-controlled coal-fired boiler. Perhaps more importantly, biomass-fired boilers produce no net CO_2 emissions, which makes the combustion of biomass an important tool in managing and reducing the Nation's carbon footprint. Similarly, biomass is an abundant, renewable domestically-produced fuel that can help reduce reliance on foreign sources of fossil fuel and, thus, improve the Nation's energy security. Prescribing overly stringent HAP emissions limitations on biomass boilers will create a significant barrier to the continued use and expansion of biomass fuels and incentivize the use of less desirable fossil fuel alternatives.
In light of the inordinate costs of complying with the proposed HAP emissions limits for biomass boilers and the strong policy reasons for promoting the combustion of biomass, EPA has ample justification to prescribe work practices and other alternative approaches rather than overly stringent HAP emissions limitations for biomass boilers.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2906.1, excerpt 5 for a response the request for work practices not emission limits. Refer to DCN EPA-HQ-OAR-2002-0058-2882.1, excerpt 7 for a response the cost impact to the forest products industry.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 165

Comment: As stated in the Clean Air Act, "if it is not feasible in the judgment of the Administrator to prescribe or enforce an emission standard for control of a hazardous air pollutant or pollutants, the Administrator may, in lieu thereof, promulgate a design, equipment, work practice, or operational standard, or combination thereof, which in the Administrator's judgment is consistent with the provisions of subsection (d) or (f) of this section. 42 U.S.C. § 7412(h). While the D.C. Circuit Court of Appeals has ruled that EPA cannot set floors of 'no control,' the court also affirmed EPA's authority under CAA § 112(h) to use work-practice standards instead of emission floors where "measuring emission levels is technologically or economically impracticable." Sierra Club v. EPA, 479 F. 3d 875, 884 (D.C. Cir. 2007). Given the limited and sporadic operation of emergency and backup boilers, as well as the technical infeasibility of imposing emission limitations on these units, the limited use subcategory should require work practices in lieu of emission limits.
In the recently promulgated CI RICE MACT, EPA set work practices including regularly scheduled maintenance and the cataloging of hours of operation to ensure compliance with relevant emission limits for emergency use engines. See National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines, 75 FR at 9655-56. As

stated by EPA, “EPA believes that work practices are appropriate and justified for this group of stationary engines because the application of measurement methodology is not practicable due to technological and economic limitations.” Id. at 9556. As further stated by EPA:

[U]sing these procedures would increase the required number of hours of operation of the engine beyond the routinely scheduled reliability testing and maintenance operation, thereby increasing emissions. While emergency engines have periods of operation for scheduled maintenance and reliability testing, those periods are usually several hours shorter than the number of hours that would be required to run the necessary emissions tests under subpart ZZZZ.

Id. at 9661. Similarly, as stated in the memorandum entitled Existing Stationary Non-Emergency CI RICE Less Than 100 HP and Existing Stationary Emergency CI RICE Located at Major Sources and GACT for Existing Stationary CI RICE Located at Area Sources (February 15, 2010) cited in EPA’s final rule:

For existing stationary CI emergency engines located at major sources, EPA determined it is not feasible to prescribe or enforce an emission standard because the application of measurement methodology to this class of engine is impracticable due to the technological and economic limitations. Emergency engines typically only operate during emergencies or during periods of routine testing and maintenance. EPA determined that application of the emissions measurement methodologies during either of these periods is not practicable. It is impracticable to test emissions from stationary CI emergency engines during periods of routine testing and maintenance using the test procedures specified in the rule because it would increase the required number of hours of operation of the engine beyond the routinely scheduled reliability testing and maintenance operation, thereby increasing emissions. While emergency engines have periods of operation for scheduled maintenance and reliability testing, those periods are usually several hours shorter than the number of hours that would be required to run the necessary emissions tests under subpart ZZZZ.

EPA also excluded black start units from HAP emission regulations in the CI RICE MACT rule. While these units operate whenever a turbine generator starts, and therefore are not limited to emergency operations, EPA nonetheless recognized the importance of exempting these units from numeric HAP standards, finding that “the short time of operation for these engines (10–15 minutes per start) makes application of measurement methodology for these engines using the required procedures, which require continuous hours of operation, impracticable. Requiring numerical emission standards for these engines would actually require substantially longer operation than would occur normally in use, leading to greater emissions and greater costs.” National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines, 75 FR at 9662.

It is worth noting that these exceptions were not created because the emissions generated have no impact on the environment. As EPA found, “[t]he majority of stationary CI engines are used for emergency purposes. EPA has estimated that 80 percent of stationary CI engines are emergency engines and EPA has taken steps in the final rule to reduce the burden on owners and operators of these engines.” National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines, 75 FR at 9658. Rather, the basis for promulgating work practices in lieu of emission standards is the impracticality of prescribing or enforcing an emission standard. See 42 U.S.C. § 7412(h).

Emergency, startup, and backup boilers, like emergency and black start CI RICE, are operated for only short periods of time and cannot feasibly be tested pursuant to EPA standards. Work practices should therefore also serve in lieu of emission monitoring and control technology for

emergency and backup boilers. For example, under 40 C.F.R. § 63.7545(d) of the Proposed Rule, a Notification of Intent must be submitted at least 30 days before any performance test. See National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters, 75 FR at 32006. As a result, even if a limited use boiler were operated for an entire month after an unplanned start, there would be no time to conduct the necessary performance tests. In addition, most test methods require steady state conditions that may not be achieved during limited use operations and, once a steady state has been reached, would require the boiler to continue operating at steady state for enough time to conduct the three 4-hour test runs required by the proposed rule for most compliance tests. See Proposed 40 CFR 63.7520(d). Even during regular operation, a limited use boiler would still need to operate for at least 12 hours in steady state condition in order to accommodate the variability attendant in these performance tests. See National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters, 75 FR at 32033 (stating that EPA selected a 12 hour averaging period for demonstrating continuous compliance "to reflect operating conditions during the performance test to ensure the control system is continuously operating at the same or better level as during a performance test demonstrating compliance with the emission limits").
1 75 Fed. Reg. at 32025. Similarly, EPA is proposing that boilers and process heaters with heat input capacities greater or equal to 100 MMBtu/hr "demonstrate that average CO emissions, on a 30-day rolling average, are at or below the proposed CO limit." National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters, 75 FR at 32034. This averaging period is essential to accommodating expected data variability, including SSM events. See, e.g. National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters; Final Rule, 69 FR at 5521. See Response to Public Comments on Proposed Industrial, Commercial, and Institutional Boilers and Process Heaters NESHAP at 102 (rejecting a 24-hour averaging period because a 30-day rolling average "accounts for the variability in fuel characteristics (e.g., moisture, Btu content, mixture) that occur for solid fuel-fired boilers and process heaters"). Without the ability to test for 30 continuous days or thereabouts, a limited use boiler could not reasonably be expected to meet the same emission limits due to their reduced ability to accommodate data variability and operators cannot adequately determine compliance with numeric emission limits.
The result would be a marked inability to practically measure emissions without operating these units for significant periods of time for the sole purpose of conducting emissions testing. As with the recently regulated emergency CI RICE, this would result in a new increase in emissions through the very effort to control emissions from these units. See National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines, 75 FR at 9655-56. Work practices are therefore the most feasible control for limited use boilers and should be adopted in the new rule.

Instead of prescribing numeric HAP emissions limitations on boilers burning clean gas fuels (the "Gas 1" subcategory), EPA proposes to adopt work practices requiring an annual tune up of the boiler. For units larger than 100 mmBtu/hr, EPA explains that "the capital costs estimated for installing controls on these boilers and process heaters to comply with MACT limits for the five HAP groups is over $14 billion."(75 Fed. Reg. at 32025) EPA further explains that:

[T]he need to employ the same emission control system as needed for the other fuel types would have the negative benefit of providing a disincentive for switching to gas as a control technique (and a pollution prevention technique) for boilers and process heaters in the other fuel subcategories. In addition, emission limits on gas-fired boilers and process heaters may have the negative benefit of providing an incentive for a facility to switch from gas (considered a “clean” fuel) to a “dirtier” but cheaper fuel (i.e., coal). It would be inconsistent with the emissions reductions goals of the CAA, and of section 112 in particular, to adopt requirements that would result in an overall increase in HAP emissions.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2808.1, excerpt 16 for a response the request for work practices not emission limits for limited-use combustors.

Commenter Name: Robert E. McKenna
Commenter Affiliation: Motor and Equipment Manufacturers Association
Document Control Number: EPA-HQ-OAR-2002-0058-2778.1
Comment Excerpt Number: 3

Comment: EPA should also establish annual tune-up work practice as the MACT standard for biomass boilers. For example, in the forest products industry alone, the estimated cost of complying with the proposed hazardous air pollutant (HAP) emissions limitations for biomass boilers is $3.3 billion. This is an extraordinary cost that, in the context of the forest products industry, equals or exceeds the magnitude of the economic burden that EPA predicts for the Gas 1 subcategory. Similarly severe economic impacts are expected in other industry sectors where biomass boilers are widely use, such as the furniture, sugar, and agricultural products industries. Thus, there is strong economic justification for prescribing work practice standards for biomass boilers in lieu of numeric emissions limitations.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2906.1, excerpt 5 for a response the request for work practices not emission limits.

Commenter Name: James Santory
Commenter Affiliation: Calgon Carbon Corp.
Document Control Number: EPA-HQ-OAR-2002-0058-2956.1
Comment Excerpt Number: 3

Comment: The regulatory approach to units in the "Gas 1" subcategory should also be applied to units in the "Gas 2" subcategory. Calgon Carbon supports that EPA’s conclusion that work practice standards are appropriate for units in the "Gas 1" subcategory in consideration of the substantial cost of compliance relative to the environmental benefit. We believe this same rationale is applicable to well-maintained units in the "Gas 2" subcategory. Calgon Carbon believes that in the majority of cases there is not a significant difference in the emissions profile of a well-maintained unit in the "Gas 2" subcategory as compared to a "Gas 1" unit. Therefore, Calgon Carbon believes the work practice standards proposed for "Gas 1" units should be similarly applied to "Gas 2" units, or alternatively, the distinction between "Gas 1" and "Gas 2" units should be removed. Work practice standards would result in significant environmental benefit, as recognized by EPA relative to "Gas 1" units, without the projected substantial economic impacts associated with the application of the proposed numeric standards on "Gas 2" units. Moreover, Calgon Carbon believes the application of work practice standards across both "Gas 1" and "Gas 2" units would encourage business and industry to continue to explore the utilization of energy sources in efficient and innovative ways.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2699.1, excerpt 1 for a response to work practices for all gas units.

Commenter Name: Randall D. Quintrell
Commenter Affiliation: Georgia Paper and Forest Products Association, GPFPA
Document Control Number: EPA-HQ-OAR-2002-0058-2905
Comment Excerpt Number: 13

Comment: Testing for HC1 and mercury for sources burning fuels known to have very low level HC1 and mercury contaminants (biomass and liquid fuel oil as discussed above) should be deleted from the final Boiler MACT Rule, and the standards for such units should be replaced with work place standards.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2906.1, excerpt 5 for a response the request for work practices not emission limits.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-2702.1
Comment Excerpt Number: 40

Comment: Another option CIBO recommends is that in lieu of a set ppm limit for CO and using a CO CEMS to demonstrate continuous compliance, EPA should borrow from the work practice standard. However, instead of tuning to minimize CO, sources would tune to maximize efficiency of combustion over the load range typical of the boiler. The typical load range can be determined using historical plant data or even the load bin-type calculations used in the Part 75 regulations. To ensure continuous compliance with the source could use the CO CEMS to monitor the boiler tune by establishing a typical range of CO for the individual unit immediately after the tune-up.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2506.1, excerpt 13 for a response the consequences of minimizing CO.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-2702.1
Comment Excerpt Number: 65

Comment: Emission Limits for Natural Gas-Fired Boilers/Process Heaters are Not Feasible and EPA Should Extend the Gas 1 Work Practices Approach to the Gas 2 Subcategory.
As discussed above, CIBO agrees with EPA's proposed approach to institute work practices for new and existing units in the Gas 1 subcategory and in the Metal Process Furnace subcategory. Emission limits for units burning natural gas are not feasible given the challenges associated with testing units with such low HAP emissions. Such an approach also would be a significant policy shift from how EPA treated these sources in the earlier Boiler MACT promulgated in 2004 and how EPA has treated natural gas-fired units in other rules.

For example, when EPA made the finding under § 112(n)(1)(A) that the regulation of electric utility steam generating units (EGUs) under § 112 is appropriate and necessary, the agency specifically determined that natural gas-fired EGUs were not included in the listing because the HAP emissions from these units "were negligible based on the results of [EPA's utility Report to Congress]." In fact, in the section of EPA's notice of finding and listing of EGUs under section 112, EPA notes that "[c]onversion of coal- and oil-fired units to natural gas firing effectively eliminates HAP emissions." Furthermore, in the NESHAP for Stationary Combustion Turbines, Subpart YYYY, EPA does not impose emission limits on existing units from any of the subcategories, including natural gas-fired units. Finally, as noted earlier, in EPA's area source proposal for boilers, natural gas-fired units are excluded from that rule because they do not emit the HAPs of concern and they are not needed to meet the 90% HAP reduction requirement in the statute. As these examples demonstrate, setting emission limits for natural gas-fired units would be a significant departure from how EPA has treated this fuel under section 112 in other rules.

The discussion above explaining why work practices are justified for natural gas-fired boilers and process heaters also serves to demonstrate why the data in the database are not reliable for setting emission standards for this subcategory of units. Given the very low-HAP emissions from natural gas-fired units, testing of these units results in data that are below or close to the detection limits for EPA's test methods or beyond the quantification capability of these tests. Thus, the data in the database are not reliable and not reproducible because the data often times represents noise as opposed to actual emissions data.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2699.1, excerpt 1 for a response to work practices for all gas units.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-2702.1

Comment Excerpt Number: 76

Comment: In lieu of emission limits, EPA has proposed work practice standards for existing units that have a design heat input capacity of less than 10 MMBtu/hr. The proposed work practice standard would include the implementation of a "tune-up" program. 75 FR 32012. EPA should not require numerical emission limits for new units that have a design heat input capacity of less than 10 MMBtu/hr. Instead, EPA should treat both existing and new units similarily, by extending work practices to new units with a design heat input capacity of less than 10 MMBtu/hr.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2906.1, excerpt 5 for a response the request for work practices not emission limits.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-2702.1
Comment Excerpt Number: 98

Comment: D. EPA should extend the work practice approach used for Gas 1 to include

Distillate Oil fired units.
While CIBO supports work practice standards, EPA should extend the work practice standard to cover distillate oil-fired units (including No.1, 2, ultra low sulfur distillate and diesel fuel, jet fuel, and other similar oils). EPA has treated distillate oil very much like it treats gas in the Proposed Rule and it should take the same approach when it comes to a work practice standard versus emission standards.

EPA established the MACT floors for liquid-fired units based on fuels that have low sulfur, chloride, and mercury content. As a result, the MACT floors were based on fuel characteristics and not on consideration of emission controls employed by the units. Considering this, EPA should not impose controls on boilers that burn a clean liquid fuel such as distillate fuel that do not contain the low chloride and mercury contents of the fuels used to establish the MACT floors. This is unreasonable, as units that burn distillate fuels have no control over the quality of the oil they receive, and will have additional costs to control very low levels of Cl and Hg to the HCl and mercury limits. In many cases it is problematic to try to design and obtain emissions controls for such low contaminant levels, since the levels in the oils are below detection levels already.

If EPA determines that work practice standards are not appropriate for distillate oil, emission limits should be changed and based on fuel oil quality or composition. This would be an acceptable approach considering distillate oil is commercial grade heating oil. EPA has no justification to impose upon ICI users of commercial fuel oil the emissions reductions that are not imposed on other uses of the same fuel oil. If EPA determines that restrictions are justified, those restrictions should be placed on the suppliers of the distillate oil to meet any limitations in quality without back-end cleanup equipment.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2906.1, excerpt 5 for a response the request for work practices not emission limits.

Commenter Name: JoAnne Rau
Commenter Affiliation: Dayton Power and Light Company
Document Control Number: EPA-HQ-OAR-2002-0058-2762.1
Comment Excerpt Number: 1

Comment: DP&L strongly recommends that the EPA modify its Proposed Rule to include a limited use exception similar to the exception established under the RICE Rule, 40 CFR 63.6590. Under the Proposed Rule, smaller oil-fired auxiliary boilers that run rarely would be required to comply with stringent emissions limits as in Table 1 and 2 of Subpart DDDDD and demonstrate compliance with those limits in Table 4 of Subpart DDDDD by following expensive monitoring and testing requirements.
The cost of such monitoring and testing is prohibitively expensive for small limited use boilers. DP&L's distillate fuel fired auxiliary boilers have a heat input range of 70 -90 MMBtu per hour and each one is used less than 200 hours per year.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2808.1, excerpt 16 for a response the request for work practices not emission limits for limited-use combustors.

Commenter Name: Richard Caserta
Commenter Affiliation: Red Hill Grinding Wheel Corp
Document Control Number: EPA-HQ-OAR-2002-0058-2996
Comment Excerpt Number: 3

Comment: EPA should, however, take the necessary next step and extend the work practice approach to all gas-fired units. Despite the exceedingly strict emissions limits that are proposed, EPA has not identified a demonstrated path to compliance for the remaining gas-fired units for which EPA has not proposed to make work practices available. Rather than imposing undue and unrealistic costs and standards on these remaining gas-fired boilers, EPA should allow work practices rather than require emissions limitations.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2699.1, excerpt 1 for a response to work practices for all gas units.

Commenter Name: John Ledger

Commenter Affiliation: Association Oregon Industries
Document Control Number: EPA-HQ-OAR-2002-0058-2925.1
Comment Excerpt Number: 3

Comment: EPA should also establish annual tune-up work practices as the MACT standard for biomass boilers. For example, in the forest products industry alone, the estimated cost of complying with the proposed HAP emissions limitations for biomass boilers is $3.3 billion. This is an extraordinary cost.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2906.1, excerpt 5 for a response the request for work practices not emission limits.

Commenter Name: Pamela F. Faggert
Commenter Affiliation: Dominion
Document Control Number: EPA-HQ-OAR-2002-0058-2908.1
Comment Excerpt Number: 3

Comment: In lieu of numerical emission limits, EPA should establish reasonable limits for PM and alternative good combustion practice and tune-up requirements for other HAPs for biomass units, just as it has proposed for units that combust natural gas. In justifying its decision to apply work practice standards in place of emission limits for gas boilers and process heaters, EPA cites a potential cost of over $14 billion for installing controls to meet such limits. EPA further notes that control requirements would provide a disincentive for fuel switching to gas as a control option for other fuel subcategories, and could even encourage some facilities to switch from gas to a cheaper fuel such as coal2. This rationale could also apply to biomass boilers and therefore provides ample support for adopting work practice standards in lieu of emission limits for boilers that burn biomass.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2906.1, excerpt 5 for a response the request for work practices not emission limits. Refer to DCN EPA-HQ-OAR-2002-0058-2882.1, excerpt 7 for a response the cost impact to the forest products industry.

Commenter Name: Richard Caserta
Commenter Affiliation: Red Hill Grinding Wheel Corp
Document Control Number: EPA-HQ-OAR-2002-0058-2996
Comment Excerpt Number: 4

Comment: EPA should also establish annual tune-up work practice as the MACT standard for biomass boilers. For example, in the forest products industry alone, the estimated cost of complying with the proposed HAP emissions limitations for biomass boilers is $3.3 billion. This is an extraordinary cost that, in the context of the forest products industry, equals or exceeds the magnitude of the economic burden that EPA predicts for the Gas 1 subcategory. Similarly severe economic impacts are expected in other industry sectors where biomass boilers are widely use, such as the furniture, sugar, and agricultural products industries. Thus, there is strong economic justification for prescribing work practice standards for biomass boilers in lieu of numeric emissions limitations.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2906.1, excerpt 5 for a response the request for work practices not emission limits.

Commenter Name: Robert L. Garfield
Commenter Affiliation: Food Industry Environmental Council
Document Control Number: EPA-HQ-OAR-2002-0058-2718.1
Comment Excerpt Number: 4

Comment: EPA should also establish annual tune-up work practice as the MACT standard for biomass boilers. For example, in the forest products industry alone, the estimated cost of complying with the proposed HAP emissions limitations for biomass boilers is $3.3 billion. This is an extraordinary cost that, in the context of the forest products industry, equals or exceeds the magnitude of the economic burden that EPA predicts for the Gas 1 subcategory. Similarly severe economic impacts are expected in other industry sectors where biomass boilers are widely use, such as the furniture, sugar, and agricultural products industries. Thus, there is strong economic justification for prescribing work practice standards for biomass boilers in lieu of numeric emissions limitations.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2906.1, excerpt 5 for a response the request for work practices not emission limits.

Commenter Name: Pamela F. Faggert
Commenter Affiliation: Dominion
Document Control Number: EPA-HQ-OAR-2002-0058-2908.1
Comment Excerpt Number: 5

Comment: A work practice standard should also be extended to industrial boiler units burning coal-derived gas. Utilities are increasingly being asked to consider constructing integrated gasification combined cycle ("IGCC") units. These units include a coal gasifier that produces gas for later combustion in a gas turbine. The gas from an IGCC unit is cleaned prior to combustion, so is not much different than natural gas or refinery gas in terms of trace HAPs. EPA should add coal-derived gas to the fuels in the Gas 1 category.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2699.1, excerpt 1 for a response to work practices for all gas units.

Commenter Name: Thomas Bakk
Commenter Affiliation: State of Minnesota Senate
Document Control Number: EPA-HQ-OAR-2002-0058-2950
Comment Excerpt Number: 9

Comment: EPA proposes work practice standards for clean gas (Gas 1) boilers rather than MACT limits because the extreme cost to comply with MACT will be a disincentive to switch to a cleaner gas fuel. We agree with this decision, but also believe that the same determination is justified for biomass boilers. The severe economic impact on forest products and other industries that operate biomass boilers will be a disincentive to continue to operate or expand the use of biomass boilers.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2882.1, excerpt 7 for a response the cost impact to the forest products industry.

Commenter Name: Holly R. Hart
Commenter Affiliation: United Steelworkers Union
Document Control Number: EPA-HQ-OAR-2002-0058-2964.1
Comment Excerpt Number: 13

Comment: USW urges EPA at the very least to implement a work practice standard for biogas boilers and all other boilers in the “other gas” subcategory, and should ensure also metal process furnaces that burn gases other than natural gas are subject to a work practice standard. These include, but are not limited to boilers that burn blast furnace gas in conjunction with any other gaseous fuel, and coke oven gas boilers.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2906.1, excerpt 5 for a response the request for work practices not emission limits.

Commenter Name: Holly R. Hart
Commenter Affiliation: United Steelworkers Union
Document Control Number: EPA-HQ-OAR-2002-0058-2964.1
Comment Excerpt Number: 16

Comment: Because of national policy, because of the issue of carbon neutrality of biomass, and because of the environmental and public health impacts of shale gas drilling technologies, and because of EPA’s statutory obligation to consider these factors, USW recommends that the biomass subcategories be evaluated to determine if there are specific pollutants that could be subjected to a work practice standard for these boilers.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2882.1, excerpt 7 for a response the cost impact to the forest products industry.

Commenter Name: Douglas A. McWilliams
Commenter Affiliation: American Municipal Power
Document Control Number: EPA-HQ-OAR-2002-0058-2808.1
Comment Excerpt Number: 16

Comment: Limited use boilers operate for only short periods of time and cannot feasibly be tested pursuant to EPA standards. Work practices should therefore serve in lieu of emission monitoring and control technology for these boilers. As stated in the Clean Air Act, "if it is not feasible in the judgment of the Administrator to prescribe or enforce an emission standard for control of a hazardous air pollutant or pollutants, the Administrator may, in lieu thereof, promulgate a design, equipment, work practice, or operational standard, or combination thereof, which in the Administrator's judgment is consistent with the provisions of subsections (d) or (f) of this section." 42 U.S.C. 7412(h). The D.C. Circuit Court of Appeals has affirmed EPA's authority under CAA section 112(h) to use work-practice standards instead of emission floors where "measuring emission levels is technologically or economically impracticable." Sierra Club v. EPA, 479 F.3d 875, 884 (D.C. Cir. 2007).
In the recently promulgated CI RICE MACT, for example, EPA set work practices including regularly scheduled maintenance and the cataloging of hours of operation to ensure compliance with relevant emission limits for emergency use engines. See 75 Fed. Reg. at 965556. As stated by EPA, "EPA believes that work practices are appropriate and justified for this group of stationary engines because the application of measurement methodology is not practicable due to technological and economic limitations." Id. at 9556. As further stated by EPA:
[U]sing these [test] procedures would increase the required number of hours of operation of the engine beyond the routinely scheduled reliability testing and maintenance operation, thereby increasing emissions. While emergency engines have periods of operation for scheduled maintenance and reliability testing, those periods are usually several hours shorter than the number of hours that would be required to run the necessary emissions tests under subpart ZZZZ.

Id. at 9661 [Footnote: It is worth noting that these exceptions were not created because the emissions generated have no impact on the environment. As EPA found, "[t]he majority of stationary CI engines are used for emergency purposes. EPA has estimated that 80 percent of stationary CI engines are emergency engines and EPA has taken steps in the final rule to reduce the burden on owners and operators of these engines." 75 Fed. Reg. at 9658. Rather, the basis for promulgating work practices in lieu of emission standards was the impracticality of prescribing or enforcing an emission standard. See 42 U.S.C. 7412(h).]

Response: EPA agrees with the commenter that it is not feasible to prescribe or enforce a numeric emission limitation on limited use units. Limited-use boilers and process heaters must complete a biennial tune-up as specified in §63.7540. They are not subject to the emission limits in Tables 1 and 2 to this subpart, the annual tune-up requirement in Table 3 to this subpart, or the operating limits in Table 4 to this subpart. See the preamble for a discussion of limited use units.

Commenter Name: Douglas A. McWilliams
Commenter Affiliation: American Municipal Power
Document Control Number: EPA-HQ-OAR-2002-0058-2808.1
Comment Excerpt Number: 17

Comment: Like emergency CI RICE, limited use boilers cannot feasibly accommodate the Boiler MACT rule's testing obligations without running for a considerably longer period than they would typically otherwise operate. Averaging less than 50 hours per month and operating as few as 15 hours per month, as is the case for the Painesville limited use unit, does not leave time for the full measure of emission tests required for solid fuel-fired units. The majority of those hours

for limited use units arc in start-up or shut-down modes that are not the steady state conditions required. 75 ed. keg. at 32052 (proposed 40 C.F.R. 63.7520(d)). [Footnote: Even during regular operation, a limited use boiler would still need to operate for at least 12 hours in steady state condition in order to accommodate the variability attendant in these performance tests. See 75 Fed. Reg. at 32033 (stating that EPA selected a 12-hour averaging period for demonstrating continuous compliance "to reflect operating conditions during the performance test to ensure the control system is continuously operating at the same or better level as during a performance test demonstrating compliance with the emission limits")] Like limited use engines. these boilers vmuld be required to extend steady state operation beyond routinely scheduled operation, thereby unnecessarily increasing emissions just to conduct the testing required by Boiler MACT. A work practice is necessary and justified because it is not technologically and economically feasible to test these sources during routine operations.

Limited use boilers cannot meet the proposed MACT floors. EPA is proposing that boilers and process heaters with heat input capacities greater or equal to 100 mmBtu/hr "demonstrate that average CO emissions, on a 30-day rolling average, are at or below the proposed CO limit." 75 Fed. Reg. at 32034. This averaging period is essential to accommodating expected data variability, including SSM events. See, e.g., 69 Fed. Reg. at 5521; see also Response to Public Comments on Proposed Industrial, Commercial, and Institutional Boilers and Process Heaters NESHAP at 102 (rejecting a 24-hour averaging period because a 30-day rolling average "accounts for the variability in fuel characteristics (e.g., moisture, Btu content, mixture) that occur for solid fuel-fired boilers and process heaters"). Measuring CO levels for 15-50 operating hours per month could not reasonably be expected to meet the same emission limits due to their reduced ability to accommodate fuel variability. As a result, operators of limited use boilers may be compelled to operate these boilers substantially longer than would otherwise be necessary to account for fuel and operations variability already factored into the tests conducted at continuously operated units.

Limited use units also present technological and economic obstacles to measuring emissions. Under 40 C.F.R. 63.7545(d) of the Proposed Rule, a Notification of Intent must be submitted at least 30 days before any performance test. See 75 Fed. Reg. at 32060. Due to this requirement, even if a limited use boiler was operated for an entire month after an unplanned start, there would be no time to conduct a properly noticed performance test.

Given the operational characteristics of limited use boilers, their sporadic and unpredictable use, the limited duration of each use, and their need for regular maintenance and readiness testing during periods of prolonged disuse, these units cannot reasonably be expected to use the measurement methodology or meet emission standards achieved by the best performing continuously operating boilers in any fuel or size category. Operators should not be forced to abandon limited use boilers, or to run them for substantially longer periods of time than they are needed for power generation in order to demonstrate MACT compliance. Abandonment of limited use utility boilers would substantially reduce the stability of the power grid, particularly during times of peak demand and for those public services where power is most necessary. On the other hand, forced extraneous operation would result in an increase in emissions, which EPA has already found renders "the application of measurement methodology . . . not practicable." 75 Fed. Reg. at 9661. Work practices consisting of tune-up and performance indicators are therefore the most feasible control for limited use boilers and should be adopted in the final rule.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2808.1, excerpt 16 for a response the request for work practices not emission limits for limited-use combustors.

Commenter Name: Kevin P. Bundy
Commenter Affiliation: Center for Biological Diversity
Document Control Number: EPA-HQ-OAR-2002-0058-2806.1
Comment Excerpt Number: 2

Comment: We understand that industry representatives have submitted, and are likely to submit, comments in each of these dockets asking that sources combusting biomass be treated differently from sources burning other fuels. Some of these comments seek either broad exemptions, or less stringent forms of regulation, under sections 112 and 129 on the basis that biomass combustion is purportedly “carbon neutral,” renewable, or otherwise environmentally beneficial.

EPA should reject these invitations to indulge in impermissible policy judgments that go beyond the text and purpose of the Clean Air Act. EPA has no authority under either section 112 or 129 to promote one type of combustion over another as a policy matter by imposing inequitable regulatory burdens on sources burning different fuels. Hazardous pollutants are hazardous pollutants, and they pose a danger to human health and the environment regardless of the fuel that produces them. Nothing in sections 112 or 129 authorizes EPA to waive or otherwise weaken MACT standards because either the agency or a regulated source category believes a fuel to have other desirable characteristics. By the same token, EPA should reject industry arguments that work practices or other alternative standards should be adopted for biomass facilities in place of MACT. There has been no demonstration that MACT is not feasible for these facilities within the meaning of section 112(h)(2).

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2882.1, excerpt 7 for a response the cost impact to the forest products industry.

Commenter Name: David Z. Skolasinski

Commenter Affiliation: Cliffs Natural Resources
Document Control Number: EPA-HQ-OAR-2002-0058-2881.1
Comment Excerpt Number: 3

Comment: Because of the standard operating procedures for the boilers as described above, it is impossible to conduct a stack test consisting of three 4-hour runs while operating the boilers at steady-state conditions near their maximum operating capacity. Because of the boiler operating cycles it is virtually impossible to even conduct a stack test consisting of three 1-hour runs. To conduct three 4-hour stack test runs, would require 12 hours of actual stack testing with one to two hours between test runs to process the collected samples, clean the equipment, and set up for the next test run. The entire process would require 15-18 hours to complete and would typically occur over a two-day period to allow reasonable working hours for the stack testing crew.

It is simply not possible to operate the boilers longer or at higher capacity than that called for to achieve the desired amount of heat in the buildings. To do so would result in exceedingly high temperatures in the buildings, which would create an unacceptable work environment in the offices as well all other buildings. There is also, no way to dissipate the heat generated by the boilers other than directing it into the building heating systems. Even if the heat could be dissipated in some other manner, it would result in a wasteful use of the fuel, which would generate unnecessary emissions of the very constituents the Boiler MACT is intended to limit. It would also result in the unnecessary generation of green house gasses and criteria pollutants, which is contrary to U.S. energy policy.
To further complicate matters the large heating boilers must be tuned up during the summer months when they are not in use. At Cliffs' mines this effort typically requires approximately 150 man-hours per boiler to dismantle the boiler, clean it, and reassemble it. In reality, the process typically requires three to four weeks per boiler with the maintenance crew working 8 hours per day and having to devote time to other maintenance tasks as well. Before the boiler can be reassembled, it must be inspected for safety and insurance purposes by a licensed state boiler inspector. Even if stack testing could be accomplished, stack tests must be scheduled several months in advance with stack testing firms. This is due to the high demand for stack testing required by numerous Clean Air Act regulatory requirements. As a result, during the heating season, operation of the boilers during a scheduled stack test is dictated by the weather conditions that occur during the stack test period.

If stack testing were even possible, the desired approach would be to arrange for a stack testing firm to conduct stack tests on all relevant boilers at a mine during a single campaign. This controls the cost of mobilization and demobilization associated with travel by the contractor to and from the mine and set up for the test. To conduct three 4-hour run stack tests on just three boilers for PM, CO, and dioxin/fiiran would require one week and would cost approximately $50,000. If an attempt was made to conduct the stack tests and the proper boiler operating requirements could not be reached and maintained, the tests would be considered invalid, and the money and effort would be wasted.

For the reasons outlined above, Cliffs strongly recommends that the final Boiler MACT Rule require only annual tune-ups of large oil-fired heating boilers with no emission limits or associated stack testing. The requirements should be the same as those for large gas-fired boilers.

Devoting resources to annual tune-ups of these boilers is the only practical and cost effective approach to controlling their emissions. While Cliffs has no experience with similar large solid fuel-fired heating boilers, it assumes that these boilers operate in a similar fashion to oil-fired heating boilers. Cliffs recommends that EPA investigate this matter, and assuming Cliffs' assumption is correct, EPA should also regulate these solid fuel-fired boilers the same as large gas-fired heating boilers.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2906.1, excerpt 5 for a response the request for work practices not emission limits.

Commenter Name: Daniel Moss
Commenter Affiliation: Society of Chemical Manufacturers and Affiliates
Document Control Number: EPA-HQ-OAR-2002-0058-2926.1
Comment Excerpt Number: 3

Comment: We support EPA's decision to establish work practice standards in lieu of emission limits for certain gas-fired boilers. EPA should provide for work practice standards for all gas- and biomass-fired boilers.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2906.1, excerpt 5 for a response the request for work practices not emission limits.

Commenter Name: Chris Welch
Commenter Affiliation: Colorado Springs Utilities
Document Control Number: EPA-HQ-OAR-2002-0058-2943.1
Comment Excerpt Number: 3

Comment: There is strong economic justification for prescribing work practice standards for biomass boilers and biogas boilers in lieu of numeric emissions limitations.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2906.1, excerpt 5 for a response the request for work practices not emission limits.

Commenter Name: Karen S. Price
Commenter Affiliation: West Virginia Manufacturers Association
Document Control Number: EPA-HQ-OAR-2002-0058-2957.1
Comment Excerpt Number: 4

Comment: EPA should also establish annual tune-up work practice as the MACT standard for biomass boilers. Severe economic impacts are expected in industry sectors where biomass boilers are widely used, such as the furniture, sugar, and agricultural products industries. (In the context of the forest products industry alone, the estimated cost of complying with the proposed HAP emissions limitations for biomass boilers is $3.3 billion dollars.)

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2906.1, excerpt 5 for a response the request for work practices not emission limits.

Commenter Name: Byron T. Burrows
Commenter Affiliation: Tampa Electric Company
Document Control Number: EPA-HQ-OAR-2002-0058-3129
Comment Excerpt Number: 4

Comment: Tampa Electric urges EPA to exempt these operations or create a limited use subcategory for auxiliary boilers subject only to limited work practice standards. The limited use subcategory could have a 10% capacity factor threshold based on 10% of the maximum hourly heat input of the boiler multiplied by 8760 hours per year. Alternatively, distillate oil-fired boilers that operate in a warm standby mode (less than 10 mmBtu/hour) a majority of the time could be subject only to work practice standards.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2761.1, excerpt 4 for a response to tune-up frequency for limited use combustors.

Commenter Name: Scott Manley
Commenter Affiliation: Wisconsin Manufacturers and Commerce
Document Control Number: EPA-HQ-OAR-2002-0058-2933.1
Comment Excerpt Number: 4

Comment: EPA should, however, take the necessary next step and extend the work practice approach to all gas-fired units. Despite the exceedingly strict emissions limits that are proposed, EPA has not identified a demonstrated path to compliance for the remaining gas-fired units for which EPA has not proposed to make work practices available. Rather than imposing undue and unrealistic costs and standards on these remaining gas-fired boilers, EPA should allow work practices rather than require emissions limitations.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2699.1, excerpt 1 for a response to work practices for all gas units.

Commenter Name: A. Steven Young
Commenter Affiliation: Association of Independent Corrugated Converters
Document Control Number: EPA-HQ-OAR-2002-0058-2899.1

Comment Excerpt Number: 4

Comment: EPA should, take the necessary next step and extend the work practice approach to all gas-fired units. Despite the exceedingly strict emissions limits that are proposed, EPA has not identified a demonstrated path to compliance for the remaining gas-fired units for which EPA has not proposed to make work practices available. Rather than imposing undue and unrealistic costs and standards on these remaining gas-fired boilers, EPA should allow work practices rather than require emissions limitations.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2699.1, excerpt 1 for a response to work practices for all gas units.

Commenter Name: Paul Lyskava
Commenter Affiliation: Pennsylvania Forest Products Association
Document Control Number: EPA-HQ-OAR-2002-0058-2906.1
Comment Excerpt Number: 5

Comment: Use the existing EPA authority to adopt a work practice standard instead of a numeric emission limit for instances where the application of a measurement methodology to a particular HAP is not practical due to technology and economic limitations.

Response: In the final rule EPA has adopted is requiring a work practice standard for particular classes of boilers and process heaters where it has determined the application of a measurement methodology is impractical. See the preamble for justification of the work practice standards and the classes of boilers and process heaters that are eligible for the tune-up in the final rule.

Commenter Name: A. Steven Young
Commenter Affiliation: Association of Independent Corrugated Converters
Document Control Number: EPA-HQ-OAR-2002-0058-2899.1
Comment Excerpt Number: 5

Comment: EPA should establish annual tune-up work practice as the MACT standard for biomass boilers. For example, in the forest products industry alone, the estimated cost of complying with the proposed HAP emissions limitations for biomass boilers is $3.3 billion. This is an extraordinary cost that, in the context of the forest products industry, equals or exceeds the magnitude of the economic burden that EPA predicts for the Gas 1 subcategory. Similarly severe economic impacts are expected in other industry sectors where biomass boilers are widely use, such as the furniture, sugar, and agricultural products industries. Thus, there is strong economic justification for prescribing work practice standards for biomass boilers in lieu of numeric emissions limitations.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2906.1, excerpt 5 for a response the request for work practices not emission limits.

Commenter Name: Robert R. Perry
Commenter Affiliation: FirstEnergy Generation Corp
Document Control Number: EPA-HQ-OAR-2002-0058-2772.1
Comment Excerpt Number: 5

Comment: Limited-use auxiliary boilers should be treated in a similar fashion as gas-fired auxiliary boilers. Electric utility operated auxiliary boilers will be subject to the ICI Boiler MACT rule because they are not steam generating units that produce electricity. As noted above, our auxiliary boilers combust either natural gas or distillate fuel and operate infrequently normally during EGU startups or to provide station heat. As a result, the HAP emissions from auxiliary boilers are very low and do not pose any risk to public health.

Under the proposed rule, gas-fired auxiliary boilers are subject to work practice standards requiring an annual tune-up. By contrast, the proposed ICI Boiler MACT rule requires oil-fired auxiliary boilers to comply with stringent ICI Boiler MACT emission limits and demonstrate compliance with those limits by implementing expensive monitoring requirements. The distinction between these two different types of auxiliary boilers is unnecessary and does not produce environmental benefits.

EPA should create a limited use subcategory for auxiliary boilers combusting distillate fuel that would subject those units to the same work practice standards as gas-fired boilers. Eligibility for this subcategory should be determined based on 10 percent of the maximum hourly heat input of the boiler multiplied by 8760 hours per year.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2808.1, excerpt 16 for a response the request for work practices not emission limits for limited-use combustors.

Commenter Name: Scott Manley
Commenter Affiliation: Wisconsin Manufacturers and Commerce
Document Control Number: EPA-HQ-OAR-2002-0058-2933.1
Comment Excerpt Number: 5

Comment: EPA should also establish annual tune-up work practice as the MACT standard for biomass boilers. For example, in the forest products industry alone, the estimated cost of complying with the proposed HAP emissions limitations for biomass boilers is $3.3 billion. This is an extraordinary cost that, in the context of the forest products industry, equals or exceeds the magnitude of the economic burden that EPA predicts for the Gas 1 subcategory. Similarly severe economic impacts are expected in other industry sectors where biomass boilers are widely used, such as the furniture and agricultural products industries. Thus, there is strong economic justification for prescribing work practice standards for biomass boilers in lieu of numeric emissions limitations.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2906.1, excerpt 5 for a response the request for work practices not emission limits.

Commenter Name: Bill Perdue
Commenter Affiliation: American Home Furnishings Alliance
Document Control Number: EPA-HQ-OAR-2002-0058-2692.1
Comment Excerpt Number: 6

Comment: The proposed rule would encourage a switch away from renewable, GHG-neutral biomass fuel to increased fossil fuel use, either domestically or overseas. In the case of the Gas 1 subcategory EPA explained that establishing a work practice standard in lieu of emission limitations is justified because it avoids counterproductive results such as switching to “dirtier” fuels. The AHFA agrees with this conclusion, and we believe it applies to dry biomass as well. By implementing work practice standards rather than a stringent emission limitation for the dry biomass subcategory, the EPA will avoid a switch away from renewable to fossil fuel sources, a switch away from GHG neutral fuels to a much larger carbon footprint, and a movement of domestic production to overseas locations.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2906.1, excerpt 5 for a response the request for work practices not emission limits. Refer to DCN EPA-HQ-OAR-2002-0058-2882.1, excerpt 7 for a response the cost impact to the forest products industry.

Commenter Name: Christian Richter
Commenter Affiliation: American Foundry Society
Document Control Number: EPA-HQ-OAR-2002-0058-2766.2
Comment Excerpt Number: 6

Comment: EPA should also consider the following for all natural gas-fired boilers and process heaters: work practices for natural gas boilers and process heaters are appropriate in lieu of emission limits.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2938.1, excerpt 1 for a response the inclusion of work practices.

Commenter Name: Douglas A. McWilliams
Commenter Affiliation: ArcelorMittal USA, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2811.1

Comment Excerpt Number: 7

Comment: For coke oven gas-fired boilers that are not excluded from Boiler MACT as waste heat boilers, EPA should require the same work practices proposed for Gas-1 units. If natural gas and coke oven gas are subject to the same work practice standards, EPA removes the disincentive for process gas energy recovery in the Rule and preserves the environmental and energy benefits discussed in the submittal.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2906.1, excerpt 5 for a response the request for work practices not emission limits.

Commenter Name: Alicia Oman
Commenter Affiliation: National Association of Manufacturers
Document Control Number: EPA-HQ-OAR-2002-0058-2845.1
Comment Excerpt Number: 7

Comment: For the reasons discussed above, EPA should establish annual tune-up work practice as the MACT standard for all other gas boilers. Other gas boilers have the same characteristics as natural gas and refinery gas. Indeed, EPA has not identified and cannot identify any technologically feasible means of achieving the stringent proposed standards that apply to all of the units in the subcategories. As discussed infra (Section II.B), EPA is therefore required to turn to other methods of control, with tune-ups as the choice justified by EPA's data. Further, many of the other gases are very similar in composition and combustion properties to the Gas 1 subcategory gasses, making a decision to have such dramatically different emission control regimes arbitrary and capricious. Finally, gaseous fuels are clean burning fuels with emissions that are lower than from other types of fuels. Just as EPA recognized that it should not be creating perverse incentives that force operators to turn away from clean Gas 1 fuels, 75 Fed. Reg. 32025, EPA should not create regulatory incentives for operators to turn away from other clean gaseous fuels. EPA should encourage the use of clean burning fuels by allowing work practices that give operating flexibility to maximize combustion efficiency and, thereby, minimize emissions.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2699.1, excerpt 1 for a response to work practices for all gas units.

Commenter Name: Wayne J. Galler and Deborah A. Phillips
Commenter Affiliation: Georgia Industry Environmental Coalition, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2882.1
Comment Excerpt Number: 7

Comment: The forest products industry estimates it will cost $3.3 billion to comply with the proposed HAP limits. This is a severe cost to impose on a single industry. Similar severe costs

are expected to result from other industry groups that bum biomass, if pollution controls must be added to comply with HAP emission standards, such as the furniture industry, sugar industry, and agricultural products industries. These control costs would lead many of.the existing biomass boiler`owners to stop burning biomass or discourage companies from switching to renewable fuels such as biomass. This also contradicts U.S_ policy
objectives to reduce our nation's reliance on fossil fuels. Biomass is a clean fuel with low concentrations of naturally occurring metals, and it is also a fuel with no net increase in the generation of greenhouse gas emissions when it is burned, therefore, we can reduce our nation's carbon footprint by encouraging the use of biomass as a fuel instead of discouraging its use by requiring expensive pollution controls to meet stringent HAP limits.

Response: EPA has revised its cost estimates in the final rule. See the preamble and RIA for revised cost estimates and response to comments on the cost issues.

With respect to the larger policy concerns on promotion of biomass, the carbon footprint of biomass and US energy policy is outside the scope of this rulemaking and will not be responded to in this document.

Commenter Name: Jennifer Klein
Commenter Affiliation: Ohio Chamber of Commerce
Document Control Number: EPA-HQ-OAR-2002-0058-2901.1
Comment Excerpt Number: 8

Comment: Instead of prescribing numeric HAP emissions limitations on boilers burning clean gas fuels (the "Gas 1" subcategory), EPA proposes to adopt work practices requiring an annual tune-up of the boiler. For units larger than 100 mmBtu/hr, EPA explains that "the capital costs estimated for installing controls on these boilers and process heaters to comply with MACT limits for the five HAP groups is over $14 billion." EPA therefore proposed that work practice standards are appropriate and justified for units in the Gas 1 subcategory out of concern for the cost of complying with numeric emissions limitations and based on the adverse policy incentives that would be created.

The rationale that supports the proposed approach for the Gas 1 subcategory applies equally well to biomass boilers and, therefore, provides ample support for adopting work practices instead of numeric emissions limitation for biomass boilers. For example, in the forest products industry alone, the estimated cost of complying with the proposed HAP emissions limitations for biomass boilers is $3.3 billion. This is an extraordinary cost that, in the context of the forest products industry, equals or exceeds the magnitude of the economic burden that EPA predicts for the Gas 1 subcategory. Similarly severe economic impacts are expected in other industry sectors where biomass boilers are widely used, such as the furniture, sugar, and agricultural products industries. Thus, there is strong economic justification for prescribing work practice standards for biomass boilers in lieu of numeric emissions limitations.

Response: EPA has revised its cost estimates in the final rule. See the preamble and RIA for revised cost estimates and response to comments on the cost issues.

With respect to the larger policy concerns on promotion of biomass, the carbon footprint of biomass and US energy policy is outside the scope of this rulemaking and will not be responded to in this document.

Commenter Name: Caroline Choi
Commenter Affiliation: Progress Energy
Document Control Number: EPA-HQ-OAR-2002-0058-2868.1
Comment Excerpt Number: 8

Comment: Because of strong policy reasons for promoting the combustion of biomass coupled with difficulty in complying with the unreasonably stringent proposed HAP emission limits for biomass boilers, Progress Energy urges the EPA to prescribe work practice standards for biomass boilers instead.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2906.1, excerpt 5 for a response the request for work practices not emission limits.

Commenter Name: Alicia Oman
Commenter Affiliation: National Association of Manufacturers
Document Control Number: EPA-HQ-OAR-2002-0058-2845.1
Comment Excerpt Number: 8

Comment: The rationale that supports the proposed approach for the Gas 1 subcategory applies equally well to biomass boilers and, therefore, provides ample support for adopting work practices instead of numeric emissions limitation for biomass boilers. For example, in the forest products industry alone, the estimated cost of complying with the proposed HAP emissions limitations for biomass boilers is $3.3 billion. This is an extraordinary cost that, in the context of the forest products industry, equals or exceeds the magnitude of the economic burden that EPA predicts for the Gas 1 subcategory. Similarly severe economic impacts are expected in other industry sectors where biomass boilers are widely use, such as the furniture, sugar, and agricultural products industries. Thus, there is strong economic justification for prescribing work practice standards for biomass boilers in lieu of numeric emissions limitations.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2906.1, excerpt 5 for a response the request for work practices not emission limits.

Commenter Name: Douglas A. McWilliams

Commenter Affiliation: ArcelorMittal USA, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2811.1
Comment Excerpt Number: 9

Comment: Should the Agency feel compelled to press forward under § 112(h) despite its authority to establish work practice-based emissions standards directly under §§112(d) and 302(k), the Proposed Rule's findings regarding the infeasibility of controlling and monitoring emissions from natural gas-fired boilers are equally applicable to coke oven gas-fired units. As found by EPA, work practices should supplant numeric emission limits on Gas-1 units because "[f]irst, the capital costs estimated for installing controls on these boilers and process heaters to comply with MACT limits for the five HAP groups is over $14 billion.'..." 75 Fed. Reg. at 32025. Second, EPA found that proposing emission standards for gas-fired boilers and process heaters "would have the negative benefit of providing a disincentive for switching to gas as a control technique (and a pollution prevention technique)" and "may have the negative benefit of providing an incentive for a facility to switch from gas (considered a 'clean' fuel) to a 'dirtier' but cheaper fuel (i.e., coal)." Id. As EPA correctly found, "[i]t would be inconsistent with the emissions reductions goals of the CAA, and of section 112 in particular, to adopt requirements that would result in an overall increase in HAP emissions." Id.

These same arguments apply with even greater force to coke oven gas-fired units. First, the costs of controlling coke oven gas-fired units are similar to the per-unit costs faced by Gas-1 units. Just like Gas-1 units, coke oven gas units would otherwise face the need to install activated carbon injection with fabric filters to control PM, mercury, and dioxin/furan, as well as wet scrubbers to control HC1, and an oxidizing catalyst to control CO - all at a cost well beyond that already calculated by EPA. [Footnote: A model coke oven gas-fired boiler would face an annual cost of $8.4 million with capital costs of $27.7 million to install the controls required for the proposed emission limits. See Table 5. The annual cost for mercury controls alone are over $6.2 million, which means the Proposed Rule is requiring over $250,000 in annual control cost for every pound of mercury reduced from coke oven gas-fired boilers.] ArcelorMittal's Burns Harbor facility alone faces over $100 million in control costs to meet the proposed limits. Second, as discussed above, imposing emission standards on these units would clearly incentivize operators to cease burning coke oven gas in preference for the fossil fuels that cost less to burn, resulting in an increase in emissions "inconsistent with the emissions reductions goals of the CAA, and of section 112 in particular." Id.

But unlike natural gas, which is generally stored as a commodity when not consumed, coke oven gas must be flared as a waste gas to ensure a safe environment if not immediately usable at a facility. As a result, creating incentives which cause operators of coke oven gas-fired units to fuel-switch (even to natural gas) would result in significant net emissions increases. That is because the facility would necessarily combust both the coke oven gas (at a flare) and the additional fossil fuel necessary to generate sufficient heat for its operations. Simply put, any standard that creates a disincentive to recover energy from process gases is bad for the environment and thus contrary to the goals of the Clean Air Act. Extending work practice tune-up standards to coke oven gas boilers will ensure that there is no environmentally-detrimental incentive to displace coke oven gas with natural gas in the boiler and flare the coke oven gas.

When the result of imposing an emission standard on a class of sources is to create economic and technological incentives that compel the operator to move the source of emissions out of the affected source and to a flare, it is no longer feasible to prescribe or enforce that emission standard. Section 112(h) of the Act allows work practices in lieu of emission standards in this circumstance. Unquestionably, EPA can justify a work practice under 112(h)(2)(B) of the Act because the "application of measurement methodology to [these boilers] is not practicable due to technological and economic limitations." HAP emissions from coke oven gas combustion cannot be measured with any methodology applied at the boiler when they are occurring at the flare. EPA may apply work practices under 112(h) to ensure that coke oven gas is not driven out of the boiler and to a flare.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2906.1, excerpt 5 for a response the request for work practices not emission limits.

Commenter Name: Nilaksh Kothari
Commenter Affiliation: Manitowoc Public Utilities
Document Control Number: EPA-HQ-OAR-2002-0058-2810.1
Comment Excerpt Number: 10

Comment: MPU recommends EPA retain the limited use subcategory as finalized in the 2004 Boiler MACT rule. MPU operates boilers in varying configurations, with some units used to backup primary units to ensure reliable electricity generation at all times. These backup units typically operate less than 10% of the time and in response to the scheduled and unscheduled downtime for primary units. These units are part of the standby capacity of a transmission network that must be reliably available to support the electric grid when need is determined by the transmission operator. These units must be operated periodically to ensure they will be reliably available upon demand to support the grid. MPU encourages EPA to adopt a limited use subcategory that acknowledges the unique challenges associated with monitoring and measuring emissions from these sources. Work practices under 112(h) are needed and appropriate for limited use public power units operating less than 10% of their annual heat input capacity to ensure reliable and efficient electricity service.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2761.1, excerpt 4 for a response to tune-up frequency for limited use combustors.

Commenter Name: Gordon M. Smith
Commenter Affiliation: Mitsubishi Polyester Film, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2912
Comment Excerpt Number: 10

Comment: We support establishing work practice standards for natural gas-fired boilers and process heaters. We believe that work practice standards are also appropriate for boilers and process heaters firing light liquids (distillate oil) for the same reasons outlined by EPA for natural gas.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2906.1, excerpt 5 for a response the request for work practices not emission limits.

Commenter Name: Douglas A. McWilliams
Commenter Affiliation: ArcelorMittal USA, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2811.1
Comment Excerpt Number: 10

Comment: Coke Oven Gas-Fired Units Also Satisfy the CAA §112(h) Work Practice Requirements Because Measurement Methodologies Are Insufficient to Reliably Quantify Their Controlled Emission Levels.

EPA may also justify work practices for coke oven gas-fired boilers on the basis that emissions after control will be below the levels that can be reliably measured. EPA should establish a work practice standard for coke oven gas-fired units because measurement of controlled emission levels after application of emission controls to achieve proposed emission limits is technically and economically infeasible.

EPA is directed to use work practices under CAA 112(h) when "application of measurement methodology to a particular class of sources is not practicable due to technological and economic limitations." When conducting a series of tests on coke oven gas-fired boilers using EPA's designated test methods in July 2010, the measurement methodology could not accurately and reliably measure concentrations for some compounds at the low levels necessary to demonstrate compliance with the proposed emission limits. Uncontrolled concentrations for coke oven gas-fired units are very low, but not low enough to meet the proposed emission limits. When applying the emission control measures assumed in EPA's Regulatory Impact Analysis, the controlled concentrations are expected to be well below the level that can be reliably measured by EPA test methods and laboratory analytical procedures. The factors that determine the levels that can be reliably measured by a measurement methodology cannot be controlled and it is economically infeasible to conduct repeated tests hoping that these factors will randomly result in acceptable detection and quantitation limits. Replacing the Gas-2 numeric emission limitations with a work practice standard for coke oven gas-fired units provides a reasonable pathway to compliance with Boiler MACT requirements.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2906.1, excerpt 5 for a response the request for work practices not emission limits.

Commenter Name: Ann W. McIver
Commenter Affiliation: Citizens Energy Group

Document Control Number: EPA-HQ-OAR-2002-0058-2875.1
Comment Excerpt Number: 11

Comment: Though Citizens commends EPA for attempting to provide for operational variability by averaging the CO concentration over a 30-day period, the proposed limits, even when a longer averaging period is considered, will be difficult to achieve given the variability in operation over a broad load range and the impacts that this has on CO emissions and combustion efficiency.

Citizens recommends that in lieu of a single limit for CO concentration (in parts per million) using a CO CEMS to demonstrate continuous compliance, that EPA utilize a work practice standard (i.e. tuning the system to maximize combustion efficiency over the load range typical for each boiler). The typical load range can be determined using historical plant data or even the load bin-type calculations used in the Part 75 regulations. To ensure continuous compliance with the "good tuning" achieved through the work practice, the source could use the CO CEMS to monitor emissions through the use of a typical range of CO (based on boiler load) for the individual unit immediately after the tune-up.

Response: EPA recognizes the inconsistency in the proposal that established a CO limit based on stack test results but required compliance demonstration with a CO CEMS. We also recognize the sensitivity of CO levels as a function of boiler load. The final rule no longer includes a requirement for a CO CEMS. Although the we appreciate the commenter suggestion to use load bin-type calculations used in the Part 75 regulations, those calculations apply to mostly very large boilers and process heaters and would be difficult to implement for load-following units that experience frequent load swings. Instead, EPA has included an O2 monitoring requirement in the final rule in order to ensure continuous compliance with good combustion efficiency on the unit.

Commenter Name: Richard Krock
Commenter Affiliation: The Vinyl Institute
Document Control Number: EPA-HQ-OAR-2002-0058-2944.1
Comment Excerpt Number: 11

Comment: Work practices should also be promulgated for boilers and process heaters combusting petrochemical and chemical process gases. All the arguments EPA makes to justify work practice requirements for natural gas/refinery gas apply to virtually all gases. These gases are clean burning fuels and are composed mainly of methane, ethane, and hydrogen.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2699.1, excerpt 1 for a response to work practices for all gas units.

Commenter Name: David P. Tenny

Commenter Affiliation: National Alliance of Forest Owners
Document Control Number: EPA-HQ-OAR-2002-0058-2750.1
Comment Excerpt Number: 13

Comment: NAFO recommends that, in the final rule, EPA eliminate the biomass unit emission limits requirements for dioxin/furan and mercury for biomass, and replace them with work practice requirements. Section 112(h)(2)(B) of the CAA authorizes EPA to establish work practice standards when "the application of measurement methodology to a particular class of sources is not practicable due to technological and economic limitations." The proposed standards are not practicable due to technological limitations.
The proposed rule already adopts work practice standards for other fuel sources. For natural gas-fired units, the proposed rule would establish a work practice standard instead of emission limits. As such, operators would be required to conduct annual or biennial tune-ups for each unit instead of adopting add-on controls. NAFO believes that for dioxin/furan and mercury, EPA's rationale that supports establishing work practice standards for natural gas-fired units applies equally well to biomass units. EPA explained in the preamble that for gas-fired units larger than 100 mm Btu/hour, "the capital costs estimated for installing controls on these boilers and process heaters to comply with MACT limits for the five HAP groups is over $14 billion." 75 Fed. Reg. at 32025. EPA further explains that "emission limits on gas-fired boilers and process heaters may have the negative benefit of providing an incentive for a facility to switch from gas (considered a 'clean' fuel) to a 'dirtier' but cheaper fuel (i.e., coal)." Id. NAFO believes that for certain HAPs a work practice standard (instead of numeric emissions limitations) is similarly warranted for biomass units. Like gas-fired units, the cost of compliance with the dioxin/furan and mercury limitations for biomass units would be extraordinary. In addition, as described above, prescribing work practice standards would avoid creating an incentive for facilities to switch from biomass, a "clean" fuel, to a higher-carbon fossil fuel. Accordingly, for dioxin/furan and mercury, EPA should establish work practices rather than emissions limitations for biomass boilers.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2906.1, excerpt 5 for a response the request for work practices not emission limits. Refer to DCN EPA-HQ-OAR-2002-0058-2882.1, excerpt 7 for a response the cost impact to the forest products industry.

Commenter Name: Edward E. Quick
Commenter Affiliation: Celanese International Corp
Document Control Number: EPA-HQ-OAR-2002-0058-2840.1
Comment Excerpt Number: 13

Comment: Work practice standards are the appropriate means of regulating distillate oil and similar fuels for a number of reasons.

First, distillate oil (No.2 Oil) is a commercially available fuel that is regulated by ASTM specifications. It is commonly used for commercial and residential heating purposes as well as by industrial, commercial, and institutional boilers and process heaters. HCI and Hg emissions are a function of chloride and mercury content of the fuel. Although chloride and mercury are not included in the ASTM specification, No. 2 oil is inherently low in these compounds by means of the refining process as dictated by the ASTM specification.

Second, work practices have been the preferred method for regulating boilers and process heaters firing distillate oil. In the past, EPA has considered distillate oil in a manner similar to natural gas when establishing requirements for emissions controls. Celanese is not aware of any boilers or process heaters fired with distillate oil, alone or in combination with gaseous fuels, that have been required to install emission controls for PM, mercury, or HCI.

Third, none of the distillate oil-fired units in the MACT floor database are equipped with PM or HCI controls. EPA reference documentation provides no basis for imposing PM and HCI emissions limits on distillate or diesel oil fired boilers and process heaters. Conversely, units firing residual oil have been required to install PM controls and acid gas scrubbers. Therefore, by grouping all liquid fuels into one category, it appears that EPA arbitrarily imposed emission limits that are based on controlled units firing residual oil onto units firing distillate oil.
Fourth, EPA recognizes that distillate oil fired units are inherently lower emitting devices that would likely meet the proposed limits by not requiring performance testing and initial compliance requirements. Since EPA recognizes that emission controls will not likely be required for distillate oil fired units, there is no purpose served by imposing those limits. The imposition of superfluous emissions limits results only in the expense and effort of unnecessary regulatory, enforcement, and compliance demonstration.

Finally, PM and HCI emission rates for distillate oil fired units are very low and, for the most part, are not controllable by the source. In other words, they could legitimately be considered de minimis.
Based on these considerations, Celanese recommends that EPA revise the requirements in the final rule and impose work practice standards for distillate oil and comparable fuels rather than emission limits. The justification for this approach is the same as for the Gas 1 category. This could be done by separating distillate oil and comparable fuels into an oil 1 category, and placing heavy residual oils into an oil 2 category.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2906.1, excerpt 5 for a response the request for work practices not emission limits.

Commenter Name: Edward E. Quick
Commenter Affiliation: Celanese International Corp
Document Control Number: EPA-HQ-OAR-2002-0058-2840.1
Comment Excerpt Number: 14

Comment: Comparable fuels should be treated the same as distillate oil relative to work practice standards. EPA established final rules revising the standards for Hazardous Waste Combustors on June 19, 1998 (63 Fed. Reg. 33781-33829) to exclude “comparable/syngas fuel” from 40 CFR 261.4 and providing specific requirements 40 CFR 261.38. As explained in the preamble to that rule, EPA used a composite specification for establishing the limits for comparable fuels.

These fuel specifications limit fuel concentrations of halogens, metals, and other compounds and therefore prevent adverse impacts to the environment. Therefore, Celanese recommends that work process standards apply to process liquid fuels meeting the comparable fuels limits.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2906.1, excerpt 5 for a response the request for work practices not emission limits.

Commenter Name: Richard Rosvold
Commenter Affiliation: Xcel Energy Services, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2955.1
Comment Excerpt Number: 16

Comment: Annual stack testing is excessive, especially for liquid-fueled units with low hours of operation. In fact, for units burning distillate fuels, periodic stack testing would be of questionable utility. Instead, we suggest extending the work practice for periodic unit tune ups to boilers burning distillate oil and biodiesel fuels. This would ensure the units are operating optimally, leading to the desired environmental benefits, while sparing these units from the cost of testing.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2906.1, excerpt 5 for a response the request for work practices not emission limits.

Commenter Name: Lee B. Zeugin
Commenter Affiliation: Utility Air Regulatory Group
Document Control Number: EPA-HQ-OAR-2002-0058-2880.1
Comment Excerpt Number: 20

Comment: The work practice standard should be extended to industrial boiler units burning coal-derived gas. Utilities are increasingly being asked to consider constructing integrated gas combined cycle (“IGCC”) units. These units include a coal gasifier that produces gas for later combustion in a gas turbine. The gas from an IGCC unit is cleaned prior to combustion so in terms of trace HAPs it is little different than natural gas or refinery gas.

In fact, some coal-gasification processes include an additional methanation step that results in the production of synthetic natural gas (“SNG”). This product is indistinguishable from natural gas and can be transported in natural gas pipelines. The proposed distinction between natural gas and other gas sources (like SNG) could create future compliance problems. How will an industrial boiler end user know whether the pipeline delivered gas containing some amount of SNG and thus whether the industrial boiler is subject to work practice standards or emission limits?

The proposed gas distinction is unworkable. All gas-fired boilers should be subject to work practice standards. If, however, EPA decides to keep the proposed distinction between gas sources, then EPA should add coal-derived gas to the fuels in the Gas 1 category.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2699.1, excerpt 1 for a response to work practices for all gas units.

Commenter Name: Robert Thornton
Commenter Affiliation: International District Energy Association
Document Control Number: EPA-HQ-OAR-2002-0058-2918.1
Comment Excerpt Number: 22

Comment: EPA should adopt a work practices standard for the limited use subcategory for two reasons:
* EPA has acknowledged that there is no proven control technology for organic HAP emissions from limited use units.
* Limited use units, such as emergency and backup boilers, cannot be tested effectively due to their limited operating schedules and because most EPA test methods require a unit to operate in a steady state (See Proposed 40 CFR 63.7520(d)).

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2808.1, excerpt 16 for a response the request for work practices not emission limits for limited-use combustors.

Commenter Name: Bill Wemhoff
Commenter Affiliation: National Rural Electric Cooperative Association
Document Control Number: EPA-HQ-OAR-2002-0058-2835.1
Comment Excerpt Number: 22

Comment: The proposed IB MACT rule requires oil-fired auxiliary boilers to comply with stringent emission limits and demonstrate compliance with those limits by following expensive monitoring requirements. The distinction between these two different types of auxiliary boilers is unnecessary and does not produce environmental benefits.

Believes EPA should create a limited use subcategory for boilers
combusting distillate fuel that would subject those units to the same work practice standards as gas-fired units. The limited use subcategory should have a 10 percent capacity factor threshold. Eligibility for this subcategory would be determined based on 10 percent of the maximum hourly heat input of the boiler multiplied by 8,760 hours per year. Providing a limited use category with the limitations described above, would not pose any risk to human health but would provide substantial economic and administrative relief to owners of these sources.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2808.1, excerpt 16 for a response the request for work practices not emission limits for limited-use combustors.

Commenter Name: Robert Thornton
Commenter Affiliation: International District Energy Association
Document Control Number: EPA-HQ-OAR-2002-0058-2918.1
Comment Excerpt Number: 26

Comment: EPA has proposed that work practice standards are appropriate and justified for units in the Gas 1 subcategory out of concern for the cost of complying with numeric emissions limitations and based on the adverse policy incentives that would be created. The rationale that supports the proposed approach for the Gas 1 subcategory applies equally well to biomass boilers and, therefore, provides ample support for adopting work practices instead of numeric emissions limitations for biomass boilers.

Use of biomass reduces net GHG emissions, which makes the combustion of biomass an important tool in managing and reducing the Nation's carbon footprint. Similarly, biomass is an abundant, renewable domestically-produced fuel that can help reduce reliance on foreign sources of fossil fuel and, thus, improve the Nation's energy security. Prescribing stringent HAP emissions limitations on biomass boilers will create a significant barrier to the continued use and expansion of biomass fuels and incentivize the use of less desirable fossil fuel alternatives.

Given the high costs of complying with the proposed HAP emissions limits for biomass boilers and the strong energy and environmental policy benefits off biomass, EPA has ample justification for requiring work practices rather than HAP emissions limitations for biomass boilers.

The proposed standards will drive energy facility managers to avoid or abandon biomass for natural gas. This will reduce fuel flexibility and the associated economic and reliability benefits of using biomass. Dependence on one fuel increases risks relative to price fluctuations and supply disruption.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2906.1, excerpt 5 for a response the request for work practices not emission limits.

Commenter Name: Sarah E. Amick
Commenter Affiliation: Rubber Manufacturers Association
Document Control Number: EPA-HQ-OAR-2002-0058-2941.1
Comment Excerpt Number: 31

Comment: As stated in the Clean Air Act, "if it is not feasible in the judgment of the Administrator to prescribe or enforce an emission standard for control of a hazardous air pollutant or pollutants, the Administrator may, in lieu thereof, promulgate a design, equipment,

work practice, or operational standard, or combination thereof, which in the Administrator's judgment is consistent with the provisions of subsection(d) or (f) of this section. 42 U.S.C. § 7412(h). While
the D.C. Circuit Court of Appeals has ruled that EPA cannot set floors of "no control," the court also affirmed EPA's authority under CAA § 112(h) to use work-practice standards instead of emission floors where "measuring emission levels is technologically or economically impracticable." Sierra Club v. EPA, 479 F. 3d 875, 884 (D.C. Cir. 2007). Given the limited and sporadic operation of emergency and backup boilers, as well as the technical infeasibility of imposing emission limitations on these units, the limited use subcategory should be limited by work practices in lieu of an emission floor.

In the recently promulgated CI RICE MACT, EPA set work practices including regularly scheduled maintenance and the cataloging of hours of operation to ensure compliance with relevant emission limits for emergency use engines. See National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines, 75 Fed.Reg. at 9655-56. As stated by EPA, "EPA believes that work practices are appropriate and justified for this group of stationary engines because the application of measurement methodology is not practicable due to technological and economic limitations." Id. at 9556. As further stated by EPA: [U]sing these procedures would increase the required number of hours of operation of the engine beyond the routinely scheduled reliability testing and maintenance operation, thereby increasing emissions. While emergency engines have periods of operation for scheduled maintenance and reliability testing, those periods are usually several hours shorter than the number of hours that would be required to run the necessary emissions tests under subpart ZZZZ. Id. at 9661.

Similarly, as stated in the memorandum entitled Existing Stationary Non-Emergency CI RICE Less Than 100 HP and Existing Stationary Emergency CI RICE Located at Major Sources and GACT for Existing Stationary CI RICE Located at Area Sources (February 15, 2010) cited in EPA's final rule: For existing stationary CI emergency engines located at major sources, EPA determined it is not feasible to prescribe or enforce an emission standard because the application of measurement methodology to this class of engine is impracticable due to the technological and economic limitations. Emergency engines typically only operate during emergencies or during periods of routine testing and maintenance. EPA determined that application of the emissions measurement methodologies during either of these periods is not practicable. It is impracticable to test emissions from stationary CI emergency engines during periods of routine testing and maintenance using the test procedures specified in the rule because it would increase the required number of hours of operation of the engine beyond the routinely scheduled reliability testing and maintenance operation, thereby increasing emissions. While emergency engines have periods of operation for scheduled maintenance and reliability testing, those periods are usually several hours shorter than the number of hours that would be required to run the necessary emissions tests under subpart ZZZZ.

EPA also excluded black start units from HAP emission regulations in the CI RICE MACT rule. While these units operate whenever a turbine generator starts, and therefore are not limited to emergency operations, EPA nonetheless recognized the importance of exempting these units from numeric HAP standards, finding that "the short time of operation for these engines (10–15 minutes per start) makes application of measurement methodology for these engines using the required procedures, which require continuous hours of operation, impracticable. Requiring numerical emission standards for these engines would actually require substantially longer operation than would occur normally in use, leading to greater emissions and greater costs." National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines, 75 Fed.Reg. at 9662.

It is worth noting that these exceptions were not created because the emissions generated have no impact on the environment. As EPA found, "[t]he majority of stationary CI engines are used for emergency purposes. EPA has estimated that 80 percent of stationary CI engines are emergency engines and EPA has taken steps in the final rule to reduce the burden on owners and operators of these engines." National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines, 75 Fed.Reg. at 9658. Rather, the basis for promulgating work practices in lieu of emission standards is the impracticality of prescribing or enforcing an emission standard. See 42 U.S.C. § 7412(h).

Emergency and backup boilers, like emergency and black start CI RICE, are operated for only short periods of time and cannot feasibly be tested pursuant to EPA standards. Work practices should therefore also serve in lieu of emission monitoring and control technology for emergency and backup boilers. For example, under 40 C.F.R. § 63.7545(d) of the Proposed Rule, a Notification of Intent must be submitted at least 30 days before any performance test. See National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters, 75 Fed.Reg. at 32006. As a result, even if a limited use boiler were operated for an entire month after an unplanned start, there would be no time to conduct the necessary performance tests. In addition, most test methods require steady state conditions that may not be achieved during limited use operations and, once a steady state has been reached, would require the boiler to continue operating at steady state for enough time to conduct the three 4-hour test runs required by the proposed rule for most compliance tests. See Proposed 40 CFR 63.7520(d).[29 Even during regular operation, a limited use boiler would still need to operate for at least 12 hours in steady state condition in order to accommodate the variability attendant in these performance tests. See National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters, 75 Fed.Reg. at 32,033 (stating that EPA selected a 12 hour averaging period for demonstrating continuous compliance "to reflect operating conditions during the performance test to ensure the control system is continuously operating at the same or better level as during a performance test demonstrating compliance with the emission limits").

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2808.1, excerpt 16 for a response the request for work practices not emission limits for limited-use combustors.

Commenter Name: Christopher S. Colman
Commenter Affiliation: Hovensa LLC
Document Control Number: EPA-HQ-OAR-2002-0058-2863.1
Comment Excerpt Number: 37

Comment: In view of the substantially higher costs faced by HOVENSA and other remote oil burning facilities for controls, we believe EPA's logic for gas fired units applies with equal force to these units. If HOVENSA is required to install physical controls for CO, PM, HCl and Hg/dioxins on each of its 23 units, as EPA projects it must do to comply with the proposed rule, an initial project scope prepared by HOVENSA estimates capital expenditures of (values removed as CBI). (See CBI submittal for methodology and spreadsheet used for estimates) This estimate spreadsheet does not include an approximately 1MM per unit cost for monitoring (18 of the 23 units would require 2 CEMS, one for CO and one for PM). And it does not include the likely (values removed as CBI) in operating costs imposed by a PM standard that will force a switch
from residual fuel oil to distillate fuel oil (since residual oil might not be able to meet EPA's stringent standards, even with add-on controls).

Because the 3 to 4 year timeframe required for compliance with a MACT standard and that time period might not coincide with turnaround schedules for many units, this rule will impose additional economic costs for shutting down units to install controls outside of a normal turnaround schedule. Shutting down one unit in a refinery typically has a domino effect requiring shutdown of other units operationally integrated with that unit. For example, if HOVENSA were to have to shut down one of its largest oil burning units, it would affect 3Vac and Coker because they are dependent on that unit for their feedstock. The average cost of an outage day on 5CDU for example is (values removed as CBI) because of its total impact on the facility. Assuming a very short 10 day outage (this is shorter than a normal shutdown) to install controls, the rule results in an additional (values removed as CBI) in costs for that unit complex alone. This forced shutdown process would have to be repeated several times to cover all the potential 23 units affected.

HOVENSA's estimated capital cost of (values removed as CBI) to comply is (values removed as CBI) the ENTIRE capital cost estimated by EPA for ALL 826 affected units and its (values removed as CBI) annual operating cost increase is (values removed as CBI) of the ENTIRE opeasting cost estimate, which included only testing and monitoring. In addition, HOVENSA faces tens of millions of dollars in operating losses from unit shutdowns to install controls. These costs are staggering in magnitude and simply not practicable for any refinery, particularly for HOVENSA. Thus, in addition to subcategorizing these facilities, we believe that these units should be subject to a work practice standard consistent with the standard for gas fired units and metal finishing furnaces.

[Footnote 36: Consistent with the preamble, the cost estimate assumes CO oxidation catalyst, fabric filter and wet scrubber and an injection system for sorbet. If either a fabric filter or wet scrubber can be eliminated, it would change the cost, but the costs would still be of a similar magnitude.]

Response: EPA thanks the commenter for describing the difficulties associated with retrofitting existing units. However, regardless of any information on that topic, the emission standards must reflect the floor level of control. Costs and emission impacts estimated for the boiler MACT standard are intended to represent national impacts. Consequently, costs for a specific facility may be lower or higher than what was estimated but on a national basis, we determined that our estimates are reasonable. We would also note that the cost algorithms include a cost factor for retrofitting existing boilers.

EPA has not expanded work practice standards beyond Gas 1 units. It should be noted that EPA has agreed that the unique considerations faced by non-continental refineries warrant a separate subcategory for these units, where data was made available. In this case, only data for mercury and CO were made available for this subcategory and the emission limits for the other pollutants are based on the data for continental liquid units.

Commenter Name: Alicia Oman
Commenter Affiliation: National Association of Manufacturers
Document Control Number: EPA-HQ-OAR-2002-0058-2845.1
Comment Excerpt Number: 41

Comment: The MACT floor for limited use boilers should be maintenance work practices because emission limitations are infeasible.

As stated in the Clean Air Act, “if it is not feasible in the judgment of the Administrator to prescribe or enforce an emission standard for control of a hazardous air pollutant or pollutants, the Administrator may, in lieu thereof, promulgate a design, equipment, work practice, or operational standard, or combination thereof, which in the Administrator’s judgment is consistent with the provisions of subsection(d) or (f) of this section. 42 U.S.C. 7412(h). While the D.C. Circuit Court of Appeals has ruled that EPA cannot set floors of “no control,” the court also affirmed EPA’s authority under CAA 112(h) to use work-practice standards instead of emission floors where “measuring emission levels is technologically or economically impracticable.” Sierra Club v. EPA, 479 F. 3d 875, 884 (D.C. Cir. 2007). Given the limited and sporadic operation of emergency and backup boilers, as well as the technical infeasibility of imposing emission limitations on these units, the limited use subcategory should be limited by work practices in lieu of an emission floor.

In the recently promulgated CI RICE MACT, EPA set work practices including regularly scheduled maintenance and the cataloging of hours of operation to ensure compliance with relevant emission limits for emergency use engines. See National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines, 75 Fed. Reg. at 9655-56. As stated by EPA, “EPA believes that work practices are appropriate and justified for this group of stationary engines because the application of measurement methodology is not practicable due to technological and economic limitations.” Id. at 9556. As further stated by EPA:

[U]sing these procedures would increase the required number of hours of operation of the engine beyond the routinely scheduled reliability testing and maintenance operation, thereby increasing emissions. While emergency engines have periods of operation for scheduled maintenance and reliability testing, those periods are usually several hours shorter than the number of hours that would be required to run the necessary emissions tests under subpart ZZZZ.

Id. at 9661. Similarly, as stated in the memorandum entitled Existing Stationary Non-Emergency CI RICE Less Than 100 HP and Existing Stationary Emergency CI RICE Located at Major Sources and GACT for Existing Stationary CI RICE Located at Area Sources (February 15, 2010) cited in EPA's final rule:

For existing stationary CI emergency engines located at major sources, EPA determined it is not feasible to prescribe or enforce an emission standard because the application of measurement methodology to this class of engine is impracticable due to the technological and economic limitations. Emergency engines typically only operate during emergencies or during periods of routine testing and maintenance. EPA determined that application of the emissions measurement methodologies during either of these periods is not practicable. It is impracticable to test emissions from stationary CI emergency engines during periods of routine testing and maintenance using the test procedures specified in the rule because it would increase the required number of hours of operation of the engine beyond the routinely scheduled reliability testing and maintenance operation, thereby increasing emissions. While emergency engines have periods of operation for scheduled maintenance and reliability testing, those periods are usually several hours shorter than the number of hours that would be required to run the necessary emissions tests under subpart ZZZZ.

EPA also excluded black start units from HAP emission regulations in the CI RICE MACT rule. While these units operate whenever a turbine generator starts, and therefore are not limited to emergency operations, EPA nonetheless recognized the importance of exempting these units from numeric HAP standards, finding that "the short time of operation for these engines (10–15 minutes per start) makes application of measurement methodology for these engines using the required procedures, which require continuous hours of operation, impracticable. Requiring numerical emission standards for these engines would actually require substantially longer operation than would occur normally in use, leading to greater emissions and greater costs." National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines, 75 Fed. Reg. at 9662.

It is worth noting that these exceptions were not created because the emissions generated have no impact on the environment. As EPA found, "[t]he majority of stationary CI engines are used for emergency purposes. EPA has estimated that 80 percent of stationary CI engines are emergency engines and EPA has taken steps in the final rule to reduce the burden on owners and operators of these engines." National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines, 75 Fed. Reg. at 9658. Rather, the basis for promulgating work practices in lieu of emission standards is the impracticality of prescribing or enforcing an emission standard. See 42 U.S.C. § 7412(h).

Emergency and backup boilers, like emergency and black start CI RICE, are operated for only short periods of time and cannot feasibly be tested pursuant to EPA standards. Work practices should therefore also serve in lieu of emission monitoring and control technology for emergency and backup boilers. For example, under 40 C.F.R. § 63.7545(d) of the Proposed Rule, a

Notification of Intent must be submitted at least 30 days before any performance test. See National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters, 75 Fed. Reg. at 32006. As a result, even if a limited use boiler were operated for an entire month after an unplanned start, there would be no time to conduct the necessary performance tests. In addition, most test methods require steady state conditions that may not be achieved during limited use operations and, once a steady state has been reached, would require the boiler to continue operating at steady state for enough time to conduct the three 4-hour test runs required by the proposed rule for most compliance tests. See Proposed 40 CFR 63.7520(d). [Footnotre: Even during regular operation, a limited use boiler would still need to operate for at least 12 hours in steady state condition in order to accommodate the variability attendant in these performance tests. See National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters, 75 Fed. Reg. at 32033 (stating that EPA selected a 12 hour averaging period for demonstrating continuous compliance “to reflect operating conditions during the performance test to ensure the control system is continuously operating at the same or better level as during a performance test demonstrating compliance with the emission limits”).] Similarly, EPA is proposing that boilers and process heaters with heat input capacities greater or equal to 100 MMBtu/hr “demonstrate that average CO emissions, on a 30-day rolling average, are at or below the proposed CO limit.” National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters, 75 Fed. Reg. at 32034. This averaging period is essential to accommodating expected data variability, including SSM events. See, e.g. National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters; Final Rule, 69 Fed. Reg. at 5521. See Response to Public Comments on Proposed Industrial, Commercial, and Institutional Boilers and Process Heaters NESHAP at 102 (rejecting a 24-hour averaging period because a 30-day rolling average “accounts for the variability in fuel characteristics (e.g., moisture, Btu content, mixture) that occur for solid fuel-fired boilers and process heaters”). Without the ability to test for 30 continuous days or thereabouts, a limited use boiler could not reasonably be expected to meet the same emission limits due to their reduced ability to accommodate data variability and operators cannot adequately determine compliance with numeric emission limits.

The result would be a marked inability to practically measure emissions without operating these units for significant periods of time for the sole purpose of conducting emissions testing. As with the recently regulated emergency CI RICE, this would result in a new increase in emissions through the very effort to control emissions from these units. See National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines, 75 Fed. Reg. at 9655-56. Work practices are therefore the most feasible control for limited use boilers and should be adopted in the new rule.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2808.1, excerpt 16 for a response the request for work practices not emission limits for limited-use combustors.

Commenter Name: Alicia Oman

Commenter Affiliation: National Association of Manufacturers
Document Control Number: EPA-HQ-OAR-2002-0058-2845.1
Comment Excerpt Number: 42

Comment: Limited use waste heat boiler.

Manufacturers request, consistent with the above discussion, that EPA require work practices for limited use waste heat boilers. Waste heat boilers use heat extracted from other industrial processes and combust fuel only for a very small duration on an annual basis. For the vast majority of the time, waste heat boilers do not burn alternative fuel at all. For waste heat boilers that primarily use waste heat for their total annual operation, the performance testing requirement (§63.7510 and §63.7520) is unreasonably costly and burdensome. Therefore, the final rule should not require performance testing requirements for limited use boilers that combust liquid fuel less than 10% of the time on an annual basis. The application of work practice standards, is more reasonable and appropriate.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2808.1, excerpt 16 for a response the request for work practices not emission limits for limited-use combustors.

Commenter Name: Alicia Oman
Commenter Affiliation: National Association of Manufacturers
Document Control Number: EPA-HQ-OAR-2002-0058-2845.1
Comment Excerpt Number: 43

Comment: EPA should subcategorize the proposed liquids subcategory into light liquids and heavy liquids and apply work practice requirements to the clean-burning light liquids subcategory. It is unfair to have distillate units set the floor for heavy oil units. Oil is an expensive fuel compared to gas or coal, and oil is usually only used because gas in not available. For remote locations without access to natural gas (such as islands and Alaska), EPA should only require a work practice for oil units, as EPA proposed for gas-1 for the same reasons EPA cited there. In the Turbine NSPS rule EPA provided some relief for remote locations. For the heavy oil subcategory, only a PM limit is warranted beyond a work practice.

Response: EPA disagrees that it should finalize a work practice standard for liquid fuel units in lieu of emission limits. While EPA recognizes that uncontrolled residual oil-fired units typically have higher PM emissions than distillate oil-fired units, add-on controls are available for these units, as well as pre-combustion technologies to reduce ash and/or metal content of the fuel.

See the discussion of further subcategorizing liquid fuel units in the Rationale for Subcategories section of this document. Also see the discussion of responses to comments for a new non-continental liquid fuel subcategory in the preamble.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 80

Comment: EPA proposes to subject existing small boilers (less than 10 MMBtu/hr heat input) to work practices (tune-ups) in lieu of numerical emission limits and ongoing stack testing. ACC supports this approach and believe that it should be expanded to cover new small boilers as well.

Boilers with heat input less than 10 MMBtu/hr are very small emission sources and the same measurement issues EPA cites for requiring only work practices on existing boilers [75 Fed. Reg. 32024] will also apply to new small boilers. It will not be feasible to measure emissions from these boilers, as the outlet stacks or vents are not likely to meet EPA test method criteria and emissions measured during a 2- to 4-hour stack test are likely below method detection limits for most pollutants being regulated under the rule, and it will be economically infeasible to install controls on these small boilers.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2906.1, excerpt 5 for a response the request for work practices not emission limits.

Commenter Name: Wayne Brandt
Commenter Affiliation: Minnesota Forest Industries
Document Control Number: EPA-HQ-OAR-2002-0058-3220
Comment Excerpt Number: 10

Comment: EPA should Adopt Work Practices, not MACT for Biomass Boilers.
EPA proposes work practice standards for clean gas (Gas 1) boilers rather than MACT limits because the extreme cost to comply with MACT will be a disincentive to switch to a cleaner gas fuel. We agree with this decision, but also believe that the same determination is justified for biomass boilers. The severe economic impact on forest products and other industries that operate biomass boilers will be a disincentive to continue to operate or expand the use of biomass boilers. This is contrary to environmental and energy policies established by the state and federal government which promote the use of biomass boilers. It's good policy because dioxin/furan emissions are typically lower, there is no net increase in greenhouse gas emissions, and there is an abundance of biomass which is a renewable, domestic energy source.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2906.1, excerpt 5 for a response the request for work practices not emission limits. Refer to DCN EPA-HQ-OAR-2002-0058-2882.1, excerpt 7 for a response the cost impact to the forest products industry.

New Data or Corrections to Existing Data

New Data Submissions

Commenter Name: Robert Ellerhorst
Commenter Affiliation: Michigan State University
Document Control Number: EPA-HQ-OAR-2002-0058-2816.1
Comment Excerpt Number: 3

Comment: MSU has collected some CO data on their PC boilers in July and August 2010 using portable equipment. This data is currently being reviewed for correctness and will be available in September.

MSU, along with the University of Purdue and the Pennsylvania State University, met with EPA's Robert Wayland and his staff on July 16, 2010. Part of this discussion involved concerns with achieving CO limits at all operating loads. As part of our commitment to Mr. Wayland during this meeting, we have attached hourly CO ppm CEMS data for MSU's CFB boiler. This data is contained in three Attachments. The attachments include 12 months of our CFB operating history. MSU can supply the data from the PC boilers in September. [See DCN:EPA-HQ-OAR-2002-0058-2816.2 through DCN:EPA-HQ-OAR-2002-0058-2816.4 for attachments]

Response: This data has been entered into the EPA database.

Commenter Name: Theresa Pugh
Commenter Affiliation: American Public Power Association
Document Control Number: EPA-HQ-OAR-2002-0058-2714.1
Comment Excerpt Number: 6

Comment: EPA should adopt a limited use category and exemptions (e.g. no limitations, no continuous emissions monitoring, etc.) for startup boilers, that provide steam to assist in the start-up of electric generating units. APPA members have noted that the map of major source boiler locations provided on EPA's web site for the proposed rule at http://www.epa.gov/airquality/combustion/actions.html does not show start-up boilers that could be subject to the proposed rule. This suggests that EPA may have not accounted for start-up boilers in developing the rule's cost and emissions performance criteria (e.g boilers from which the best performing 12% of could be determined), and therefore the proposed emissions limitations may be deficient because they are based on incomplete data.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2998.1, Excerpt Number 28.

Commenter Name: Robert R. Scott

Commenter Affiliation: New Hampshire Department of Environmental Services, Air Resources Division
Document Control Number: EPA-HQ-OAR-2002-0058-2734.1
Comment Excerpt Number: 7

Comment: NHDES is concerned about the limited data used for setting the emission limitations in the area and major source regulations. In the case of data availability, NHDES recommends that EPA utilize certified stack test data submitted by the states via the National Association of Clean Air Agencies (NACAA) to develop a more robust data set when developing emission limits.
NHDES suggests that EPA use all available certified data along with appropriate subcategories to develop accurate emission limitations that will result in actual HAP emission reductions while taking into consideration the effect these limits will have on emissions of other pollutants

Response: See response for DCN EPA-HQ-OAR-2002-0058-2841.1, Excerpt Number 9.

Commenter Name: Stephen R. Gossett
Commenter Affiliation: Eastman Chemical Company
Document Control Number: EPA-HQ-OAR-2002-0058-3137.1
Comment Excerpt Number: 17

Comment: To grant this request for an alternate limit for THC, EPA needs to gather additional THC data. However, there is some data available in the record to begin this analysis. For PC boilers, EPA obtained 30 days of THC and CO CEMS data from a Phillip Morris unit in Virginia. This data is displayed in Figure 16. The Upper Predicted Level at a 99 percent confidence interval for this data is 6 ppm (@3 percent O2) excluding the three startup periods and 18 ppm including the startup periods. For stoker boilers, EPA obtained 30 days of THC and CO CEMS data from a DuPont unit in West Virginia. This data is displayed in Figure 17. However, this boiler never ran below 50 percent load and no startups were included in the data, so this data really cannot be used to set an appropriate standard. Eastman proposes that EPA include the use of THC in lieu of CO , and that EPA collect additional data to establish a reasonable standard that reflects both steady-state and SSM operation. Eastman would be willing to collect such data to promote sound data-based decision making.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2841.1, Excerpt Number 9.

Commenter Name: N/A
Commenter Affiliation: Sierra Club, Clean Air Task Force, Earthjustice, and Natural Resources Defense Council
Document Control Number: EPA-HQ-OAR-2002-0058-3187.1
Comment Excerpt Number: 20

Comment: EPA's floors for ICIBPH are based on some of the data available to the Agency via information collection requests, undertaken both in support of this rulemaking (undertaken in 2007-2009) and in support of the Agency's previous (and now vacated) 2004 rules for this industrial category. However, EPA has arbitrarily refused to consider actual emissions data for major source boilers gathered by the National Association of Clean Air Agencies (NACAA). As the agency itself has stated, "EPA must consider available emissions information to determine the MACT floors." 75 Fed. Reg. at 32019 (emphasis added). Because the NACAA data is "available" to EPA, the agency must consider it in setting floors.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2841.1, Excerpt Number 9.

Commenter Name: Stephen R. Gossett
Commenter Affiliation: Eastman Chemical Company
Document Control Number: EPA-HQ-OAR-2002-0058-3137.1
Comment Excerpt Number: 21

Comment: EPA should use the data submitted with these comments to include the variability for this boiler.

Response: The provided data is not in a format suitable for inclusion in the rulemaking efforts.

Commenter Name: Stephen R. Gossett
Commenter Affiliation: Eastman Chemical Company
Document Control Number: EPA-HQ-OAR-2002-0058-3137.1
Comment Excerpt Number: 22

Comment: While none of Eastman's units were identified as top performers for mercury, we have included Figures 7 and 8 to show how our coal supply varies. Also, to assist with further statistical analysis, we have included both mercury and chlorine data from two of our powerhouses [See Excel file on CD submitted to the docket] which illustrates the variability over a five year period of time.

Response: The provided data is not in a format suitable for inclusion in the rulemaking efforts.

Commenter Name: Stephen R. Gossett
Commenter Affiliation: Eastman Chemical Company
Document Control Number: EPA-HQ-OAR-2002-0058-3137.1
Comment Excerpt Number: 24

Comment: EPA needs to do is collect coal chlorine data and mercury either directly from the sources (as Eastman is providing today) or from the suppliers that serve the top performers. If units do not have a large data set such as Eastman's, then EPA should collect chlorine data available from the coal suppliers.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2841.1, Excerpt Number 9.

Commenter Name: Stephen R. Gossett
Commenter Affiliation: Eastman Chemical Company
Document Control Number: EPA-HQ-OAR-2002-0058-3137.1
Comment Excerpt Number: 42

Comment: To add to the record that startups and shutdowns do have a significant impact on 30 day average CO emission levels, Eastman is submitting data from a CO CEMS on one of our stoker boilers. First, in Figure 3 of the submittal, we include data from a startup period for this boiler that shows the significant CO emissions incurred. As shown, the CO CEMS is actually out of span during part of this period. This adds to the argument that 30 day averages should exclude periods of startup and shutdown.

Response: The provided data is not in a format suitable for inclusion in the rulemaking efforts.

Commenter Name: Stephen R. Gossett
Commenter Affiliation: Eastman Chemical Company
Document Control Number: EPA-HQ-OAR-2002-0058-3137.1
Comment Excerpt Number: 43

Comment: We have included Figure 11 of the submittal which shows 10 months of data from another of our stoker boilers. This graph clearly shows the impact of startups on a 30 day rolling average CO emission.

Response: The provided data is not in a format suitable for inclusion in the rulemaking efforts.

Commenter Name: Arnold Schwarzenegger
Commenter Affiliation: Governor Arnold Schwarzenegger
Document Control Number: EPA-HQ-OAR-2002-0058-2697.1
Comment Excerpt Number: 6

Comment: The proposed MACT Standards did not take into account California's long history of comprehensive toxics control programs. ARB's statewide air toxics program was established in the 1983 under the Toxic Air Contaminant Identification and Control Act (AB 1807, Tanner) which created California's program to reduce exposure to air toxics. The Air Toxics "Hot Spots" Information and Assessment Act (AB 2588, Connelly 1987) supplemented the AB 1807 program, by requiring a statewide air toxics inventory as well as notification of people exposed to a significant health risk. Facilities that are found to pose a significant health risk to the community are required to reduce their risk below the level of significance through a risk management plan. All HAPs identified by U.S. EPA are included in California's list of toxic air contaminants (TAC) and additional chemicals have also been added to the list by ARB, based on toxicity and potential exposure. Over 600 substances have been listed under the Act.

In addition, districts include a TAC review during the permitting process for new and modified facilities. Sources emitting TACs must comply with district requirements regarding risk assessment and risk management of TAC emissions. Screening analyses and health risk assessments are performed as part of the permitting process. In the case of unacceptable health risks, districts require mitigation to reduce the risk.

Since the goal of U.S. EPA in developing any MACT standard is to reduce public exposure to hazardous air pollutants, any analysis conducted should include consideration of existing state programs that accomplish or contribute to the same goal.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2841.1, Excerpt Number 9.

Commenter Name: William L. Kovacs
Commenter Affiliation: United States Chamber of Commerce
Document Control Number: EPA-HQ-OAR-2002-0058-2799.1
Comment Excerpt Number: 2

Comment: Under the IQA, EPA's determination must be accurate, reliable and unbiased, and must be presented objectively. The IQA requires that all agency documents disseminated to the public must meet "a basic standard of quality," defined in terms of objectivity, utility and integrity. On its face, the Boiler MACT rule fails to meet the IQA's basic standard of quality. EPA's selection of the "best of the best" as the MACT floor suggests an obvious lack of objectivity. Failure to account for 50 to, in some cases, almost 90 percent of the sources in a subcategory when setting a MACT floor suggests an equally obvious lack of accuracy. These comments constitute a formal request for correction of the Boiler MACT data deficiencies as provided for in the IQA.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2998.1, Excerpt Number 28.

Commenter Name: Douglas A. McWilliams
Commenter Affiliation: American Municipal Power
Document Control Number: EPA-HQ-OAR-2002-0058-2808.1
Comment Excerpt Number: 3

Comment: AMP and the City of Painesville ask that EPA allow time after the close of the comment period for the submission of data from stack testing currently underway on HCI emissions from the Painesville stoker units so that the data can be quality assured and quality controlled prior to submission. Given the small amount of data available, we encourage EPA to incorporate these new data into the MACT floor analysis as the best available information for stoker emissions rates. Public Comments (Dec. 2, 2008).

Response: EPA did not receive the additional HCl test data from this facility. In the final rule, we considered data submitted up until November 17, 2010, which was the latest allowable date to consider new data given the regulatory development process and current rule schedule.

Commenter Name: Catharine Fitzsimons
Commenter Affiliation: Iowa Department of Natural Resources
Document Control Number: EPA-HQ-OAR-2002-0058-2767.1
Comment Excerpt Number: 5

Comment: EPA acknowledged that it did not use any of the emission test reports compiled from state and local program files that NACAA provided to EPA in the summer of 2008. Instead, it appears that EPA based its calculations on a "new" data set that incorporates data collected by facilities. IDNR is not commenting on whether EPA should or should not have used the emissions data provided by NACAA in 2008. However, IDNR does agree with NACAA that EPA has not provided a sufficient explanation for why EPA did not include any of the emission data provided by NACAA. EPA has an obligation under the CAA to consider all emissions data. Given the limited number of sources that EPA evaluated in each source category, it is particularly important that EPA consider all emission data available, and provide a reasonable explanation for why it chooses to exclude such data from its analysis.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2841.1, Excerpt Number 9.

Commenter Name: John C. deRuyter
Commenter Affiliation: DuPont
Document Control Number: EPA-HQ-OAR-2002-0058-2793.1
Comment Excerpt Number: 9

Comment: DuPont submitted CO CEMS data when firing LFG in this boiler for the ICR and a most recent emission test for PM for this boiler. We are also submitting with these comments for your reference earlier emissions test reports for this boiler when firing natural gas only and when cofiring natural gas and LFG.

Response: This data has been entered into the EPA database.

Commenter Name: Paul Kramer
Commenter Affiliation: Koda Energy
Document Control Number: EPA-HQ-OAR-2002-0058-2895.1
Comment Excerpt Number: 2

Comment: [See submittal for HCI Stack Test Data Koda Energy]

Response: This data has been entered into the EPA database.

Commenter Name: Michele E. Pugh
Commenter Affiliation: Flint Hills Resources, LP
Document Control Number: EPA-HQ-OAR-2002-0058-2910.1
Comment Excerpt Number: 2

Comment: While CO CEMS data is not available for the 1998 period when the stack test occurred, current CEMS data indicate that the boilers operate on a higher average CO concentration (see Attachment 1 for CEMS operating data for the first four months of 2010).

Response: This data has been entered into the EPA database.

Commenter Name: Michael Potter
Commenter Affiliation: Goodyear Tire and Rubber Company
Document Control Number: EPA-HQ-OAR-2002-0058-3181
Comment Excerpt Number: 5

Comment: EPA's cost estimates are inadequate.

Although the comment period did not provide enough time to conduct a thorough review of EPA's database, it appears that only three of Goodyear's boilers with oil-firing capability, located at only one plant location, were included in EPA's cost estimate database. Because only three of Goodyear's sixteen potentially regulated boilers were considered when EPA developed its cost estimate information, Goodyear expects that EPA's estimate of potential cost to Goodyear — and potentially other companies as well —is several times too low. Such a costly proposal warrants a thorough and complete cost analysis, and for that purpose, Goodyear is concerned that EPA's cost analysis may be inadequate and should be reconsidered.

Response: The additional Goodyear liquid boilers have been added to the inventory of units and will be factored into future analyses.

Commenter Name: Ted Sturdevant
Commenter Affiliation: Washington Department of Ecology
Document Control Number: EPA-HQ-OAR-2002-0058-2987.1
Comment Excerpt Number: 6

Comment: EPA should use the best available data to set emission standards, including data provided by the National Association of Clean Air Agencies (NACAA) and individual states. EPA should set emission standards based on what real world best performing units actually achieve, and establish emission limits consistent with and attainable by the best performing units within the boiler and fuel types covered by this rule.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2841.1, Excerpt Number 9.

Commenter Name: David M. Kiser
Commenter Affiliation: International Paper Company
Document Control Number: EPA-HQ-OAR-2002-0058-2777.1
Comment Excerpt Number: 8

Comment: To further demonstrate the highly variable nature of CO, International Paper is submitting CO data for the boilers listed in the table below. [See submittal for table summarizing CO emissions from multiple boilers.]

While the facility in Franklin, Virginia was shutdown in 2010 (as communicated in an April 1 memo to Jim Eddinger and Brian Shragger of EPA), the attached data (see Attachment 3 and 4) shows how CO can significantly vary even on a 30-day rolling average.

Response: This data has been entered into the EPA database.

Commenter Name: Kevin M. Dempsey
Commenter Affiliation: American Iron and Steel Institute
Document Control Number: EPA-HQ-OAR-2002-0058-2998.1
Comment Excerpt Number: 9

Comment: To gain a better understanding of the potential risk faced by coke oven gas-fired units under the broad Gas 2 subcategory proposed by EPA, an AISI member company conducted stack tests on four coke oven gas-fired boilers in July 2010. The test results confirm that the proposed Gas 2 emission limits for HCl, Hg, and CO are not achievable for these coke oven gas-fired boilers using commercially available emission control technologies. The tests were performed on four identical tangentially-fired industrial boilers. Each boiler has a rated heat input capacity of 650 MMBTU/hour and fires only gaseous fuels, comprised of a mixture of coke oven gas and blast furnace gas with supplementary natural gas, that are supplied to the boilers from common headers for each fuel. Typical fuel gas analyses are provided in Table 1. [see submittal for Table 1. typical process gas analysis.] The boilers operated at 73% to 87% (average 83%) of design heat input capacity during the tests. The average contribution of each fuel to total heat input during the tests was 50% coke oven gas, 39% blast furnace gas and 11% natural gas (Table 2) [see submittal for table 2: fuel heat input to each unit tests .]

The test program included the following measurements in each boiler stack:

Group A:

CO by EPA Method 10;

Dioxins and furans by EPA Method 23;

HCl and filterable non-sulfuric acid PM by EPA Method 26A, combined with EPA Method 5B;

Group B:

Hg and filterable non-sulfuric acid PM by EPA Methods 29 and 101A, combined with EPA Method 5B (modified);

Stack gas flow rate by EPA Method 2 (all tests); and

Oxygen, carbon dioxide and moisture concentration by EPA Methods 3A and 4 (all tests).

Three 4-hour test runs were performed on each of the four boilers. Group A and Group B tests were not conducted simultaneously. Tests were performed at approximately the same time of day and under comparable operating conditions. The test methods for CO, Hg, HCl and dioxins/furans are among those specified by EPA for tests conducted under the ICR for this rule and in Table 5 to Subpart DDDDD of Part 63 – Performance Testing Requirements of the proposed rule. [The test method for dioxins/furans was left blank in Table 5 of the proposed rule. EPA should correct this oversight in the final rule. We assume that Method 23 is the intended method for these compounds based on the preamble discussion at 75 Fed. Reg. 32013.]

Response: The provided stack test data for the coke oven gas-fired boilers have been added to the EPA database and will be factored into future analyses.

Commenter Name: Douglas A. McWilliams
Commenter Affiliation: ArcelorMittal USA, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2811.1
Comment Excerpt Number: 15

Comment: To better understand the potential risk faced by coke oven gas-fired units under the broad Gas-2 subcategory proposed by EPA, stack tests were conducted on four coke oven gas-fired boilers during July 2010. [See submittal for Appendix A: Draft Test Results.] The test results confirm that the proposed Gas-2 emission limits for HC1, mercury and CO are not achievable for these coke oven gas-fired boilers using commercially available emission control technologies. The tests were performed on four identical tangentially-fired industrial boilers. Each boiler has a rated heat input capacity of 650 MMBM/hr and fires only gas fuels, comprised of a mixture of coke oven gas and blast furnace gas with supplementary natural gas, that are supplied to the boilers from common headers for each fuel. Typical fuel gas analyses are provided in the submitted Table 1. The boilers operated at 73% to 87% (average 83%) of design heat input capacity during the tests. The average contribution of each fuel to total heat input during the tests was 50% coke oven gas, 39% blast furnace gas and 11% natural gas (See the submittal for Table 2).

The test program was conducted in two groups and included the following measurements in each boiler stack:

Group A:
Carbon monoxide by EPA Method 10;
Dioxins and furans by EPA Method 23;
Hydrogen chloride and filterable non-sulfuric acid particulate matter by EPA Method 26A, combined with EPA Method 5B;
Group B:
Mercury and filterable non-sulfuric acid particulate matter by EPA Methods 29 and 101A, combined with EPA Method 5B (modified);
Stack gas flow rate by EPA Method 2 (all tests); and

Oxygen, carbon dioxide and moisture concentration by EPA Methods 3A and 4 (all tests).

Three 4-hour test runs were performed on each of the four boilers. Group A and Group B tests were not conducted simultaneously. Tests were performed at approximately the same time of day and under comparable operating conditions. The test methods for CO, mercury, HC1 and dioxins/furans were among those specified by EPA for tests conducted under the Information Collection Request for this rule and in Table 5 to Subpart DDDDD of Part 63 — Performance Testing Requirements of the proposed rule. [Footnote: The test method for dioxins/furans was left blank in Table 5 of the proposed rule. EPA should correct this oversight in the final rule. We assume that Method 23 is the intended method for these compounds based on the preamble discussion at 75 Fed. Reg. 32013.]

Method 5B was selected for filterable particulate matter because it is believed to be a superior surrogate for non-mercury metallic HAPs when sulfuric acid may be present, as discussed in Section III of these comments below. SO2 concentrations in the exhaust gas indicate that sulfuric acid may be present at concentrations on the order of 5-7 ppmv, which represents a potentially large fraction of the proposed filterable particulate emission limit (on a lb/MMBtu basis). Method 5B is designed to mitigate the effect of sulfuric acid on the filterable particulate matter results, which allows for a more accurate surrogate for non-mercury metallic HAP. For the Method 29 and Method 101A tests, filterable particulate matter samples were collected with the probe and filter temperature at 160 °C as specified in Method 5B, but the laboratory analysis was modified by drying the samples in a desiccator at room temperature as specified in Methods 29 and 101A rather than in an oven at 160 °C as specified in Method 5B, so that mercury was preserved in these samples. For the Method 26A tests, Method 5B was performed normally.

The test results show highly variable CO emissions with an average concentration 28 times higher than the proposed limit. Also, HC1 and mercury exceed the proposed limits by more than an order of magnitude (Table 3 and Figure 1) rendering them unachievable. Highly variable CO results among the four identical units were not unexpected due to the presence of blast furnace gas in the fuel mix. [Footnote: Blast Furnace Gas contains large amounts of carbon monoxide and no organic HAP, thus the presence of CO in the exhaust gas from BFG fuel mixtures may not be an indication of the presence of organic HAP. The highest CO was observed during tests on Boiler 12, which is attributed to the higher relative contribution of blast furnace gas at that boiler.] the nature of these low Btu fuels, and normal variations in boiler operations even at a relatively constant total heat input near design capacity. These short duration tests cannot capture the full range of normal operating conditions that might be experienced over several years. However, they are important indications that COG-fired units are significantly different from other Gas-2 units and that further data and analysis are needed before EPA can establish non-arbitrary numeric emission limits for COG-fired units.

The levels of HC1, mercury and CO exceed the proposed Gas-2 limits by such a large margin that available emission control measures would be insufficient to achieve the proposed Gas-2 limits. If optimistic assumptions for control efficiency are applied to the uncontrolled levels measured in these tests, it is clear that the Gas-2 emission limits cannot be reliably achieved (Table 4). Even assuming 99% HC1 removal (which is overly optimistic given the low inlet HC1 concentrations and challenges associated with optimizing scrubber performance when burning variable mixed gas fuels), the proposed Gas-2 limits could not be achieved. While activated carbon injection has been reported to effectively reduce mercury emissions between 70 and 90+% at the much higher inlet mercury concentrations present in waste incinerators and coal-fired boilers, such efforts will be less effective for the very low inlet concentrations found in coke oven gas-fired boilers. Optimistically assuming 80% control efficiency, controlled mercury levels will be 5 to 10 times higher than the proposed Gas-2 limits. CO reduction efficiency by oxidation catalysts is reported to be effective in gas turbine applications; however, boiler stack gas temperatures are much lower than catalyst temperatures in those applications, and oxidation catalyst efficiency decreases with decreasing temperature. Even assuming a (likely unrealistic) CO reduction efficiency of 90%, it would not be possible to achieve or reliably detect the post-control results the Gas-2 emission limits in 3 of the 4 cases.

Response: The provided stack test data for the coke oven gas-fired boilers have been added to the EPA database and will be factored into future analyses.

Commenter Name: Traylor Champion
Commenter Affiliation: Georgia-Pacific LLC
Document Control Number: EPA-HQ-OAR-2002-0058-2745.1
Comment Excerpt Number: 26

Comment: EPA has listed several GP boilers in the MACT floor and must include other test data for these units
To calculate the MACT floor, EPA identified best performers from the lowest reported test of these units and also included other test results from these units in the calculation. The Memo (and underlying data base) list several GP units as being best performers and EPA includes them in calculation of the MACT floor. GP has other test results from these EPA-identified units that should also be included in its database. The submittal includes Table 13a shows the by-run test results from these tests. The full test reports will be made available to the Agency upon request. As noted in the comments field, some of the tests in Table 13a were conducted using a single ESP field or low voltage on the ESP or at unusually high or low steam loads. These conditions were run to simulate operation under upset conditions during normal operation when a malfunction of the ESP occurs. Because these types of upsets do occur, even at the best performing units, EPA must include these data in its floor analysis.

Response: This data has been entered into the EPA database.

Data Corrections

Commenter Name: Ritchie Monteith
Commenter Affiliation: AbitibiBowater - Catawba Operations
Document Control Number: EPA-HQ-OAR-2002-0058-0849.1
Comment Excerpt Number: 3

Comment: The database used to develop the rule contained some errors. If EPA used its discretion to set reasonable limits from good data, EPA would continue to protect public health without driving industry out of business with unrealistic control requirements.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2998.1, Excerpt Number 28.

Commenter Name: Houston Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1876
Comment Excerpt Number: 50

Comment: EPA has collected significant data over the past several
months. It has worked to make that data available for
review. As the public has reviewed this data it is
clear that EPA needs to perform additional quality
assurance to ensure that the data is accurate. Data
review has found inconsistent treatment of non-detect

values, improper classification of boilers, and gaps in
data that could be improved with additional quality
assurance. MeadWestvaco believes that this step is
crucial before EPA can realistically propose such
standards.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2998.1, Excerpt Number 28.

Commenter Name: Thomas P. Greene, III
Commenter Affiliation: Atlantic Wood Industries, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-1599.1
Comment Excerpt Number: 2

Comment: There are some apparent errors in the various data sets. EPA should stop the rulemaking until adequate data validation and analysis is completed and should re-propose the rules after this validation and analysis is complete, even if a court ruling for additional time is needed.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2998.1, Excerpt Number 28.

Commenter Name: A. Daniel White
Commenter Affiliation: T.R. Miller Mill Company, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-1597.1
Comment Excerpt Number: 7

Comment: The data EPA used to develop these rules are flawed. There are some apparent errors in the various data sets. EPA should stop the rulemaking until adequate data validation and analysis are completed and should re-propose the rules after this validation and analysis are completed.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2998.1, Excerpt Number 28.

Commenter Name: Charles McRae
Commenter Affiliation: Rex Lumber
Document Control Number: EPA-HQ-OAR-2002-0058-1846
Comment Excerpt Number: 7

Comment: EPA should use all of the available data and get additional data, if needed, to avoid setting limits for thousands of boilers based on data from only a few. In some cases, the proposed limits are based on only one or two data points, and there are some apparent errors in the various data sets. EPA should stop the rulemaking until adequate data validation and analysis is completed and should re-propose the rules after this validation and analysis is complete.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2998.1, Excerpt Number 28.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute and National Petrochemical and Refiners Association
Document Control Number: EPA-HQ-OAR-2002-0058-0851.1
Comment Excerpt Number: 8

Comment: We believe the estimate of the number of boiler and process heaters impacted by this proposal is significantly understated. We note for instance that the proposal for the vacated Boiler and Process Heater NESHAP estimated at 68 FR 1687 (January 13, 2003) that there would be a total of 58,200 affected existing units versus the current estimate of 13,555, suggesting an under-counting by more than a factor of 4. That original estimate was based on input from a vast number of sources during the Industrial Combustion Coordinated Rulemaking (ICCR) effort. Similarly, the 2003 proposal estimated 3463 new units per year rather than the 46 units per year estimated here. The RIA for that rulemaking [Footnote: EPA-452/R-04-002 (February 2004)] details the development of their estimate in Section 3.

Response: See response for DCN EPA-HQ-OAR-2002-0058-1778, Excerpt Number 75.

Commenter Name: Los Angeles Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1778
Comment Excerpt Number: 44

Comment: We note in the database that although fully one-third of the biomass power industry is in California, only one of our plants was included in the database. We would like a much more thorough explanation of how the best performing or even the plants in the database were selected.

Response: See response for DCN EPA-HQ-OAR-2002-0058-1778, Excerpt Number 75.

Commenter Name: Houston Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1876
Comment Excerpt Number: 62

Comment: Rules should not be promulgated on suspect data, and EPA should halt these proceedings until a thorough data validation has been completed.
Most boilers burning biomass burn only biomass.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2998.1, Excerpt Number 28.

Commenter Name: Los Angeles Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1778
Comment Excerpt Number: 75

Comment: U.S. EPA database at facilities with boilers and process heaters is significantly in error and fails to list numerous facilities.
For example, in Wilmington you left out Tesoro Oil Refinery, Valero Oil Refinery, Ultramar Special Products Refinery, which is an asphalt facility, and the Valero Wilmington Asphalt Plant. In the city of Carson, which is not in the database, is the BP Arco Oil Refinery, the ConocoPhillips Asphalt Specialty Products Facility, the Equilon Enterprises Asphalt Facility and the Tesoro Refinery Marketing Salt Recovery Facility.
In the city of El Segundo you left out the Chevron Oil Refinery. In the City of Long Beach at the Port of Long Beach you left out an incinerator facility, which I don't know the name of but it's there.
To give you a quick reference, you can see by this map that was put together by the California Air Resources Board. Going back in 2005, Wilmington was part of a study to identify toxic sources.
This one right here shows you different little dots that identify the various toxic sources.
And what I'm referring to here is that Wilmington is a poster child for having the most significant human impact resources in one community. The next step that we were supposed to do was a follow-up in doing a ground trooping that had anything else that was missing, but ARB has not continued the project since that time, and so we only have achieved up to this point -- and I will be submitting a copy of this map in a smaller volume and a digital format so that you do have it.
We request that the U.S. EPA validate its boiler and heater facility list with state regulatory

agencies such as CAL-EPA, California Air Resources Board and our local HMDs and, in our particular case, South Coast Air Quality Management District.
If the U.S. EPA boiler facility list is off by at least ten major facilities in Wilmington, that means the total emissions inventory is also significantly underestimated by at least ten times. And if the emissions inventory is estimated by at least ten times, that means our health impact assessment and the numbers that are coded are also underestimated at least by ten times in our community.

Response: EPA has updated its inventory based on comments received during the public comment period. Among the refineries listed by the commenter, the following were added to the database: In Wilmington, CA, the Tesoro and Valero oil refineries were added. In Carson, CA, the BP Arco oil refinery and ConocoPhillips Asphalt Specialty Products facility were added. The Chevron oil refinery in El Segundo, CA, was added. The remaining facilities listed were not added to the database due to the inability to obtain information on their applicable combustion units.

Commenter Name: Los Angeles Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1778
Comment Excerpt Number: 80

Comment: I am concerned that your list of toxic facilities with boilers or incinerators is not accurate and complete. Your list doesn't include BP-Arco Oil Refinery. It also doesn't include specialty product oil refineries such as:
A) ConocoPhillips Company, Carson Refinery.
B) Equilon Enterprises, LLC, Shell Oil Products U.S.A. Desoto (phonetic) Refinery and Marketing Company, a sulphur recovery plant. Specialty products include sulphur recovery facilities and asphalt refineries.
Point two, as a result, your boiler toxic emissions are significantly underestimated in my environmental justice community of Carson.
Point three, therefore your public health risk assessment is also significantly underestimated and must be updated and a monitoring system must be implemented.

Response: See response for DCN EPA-HQ-OAR-2002-0058-1778, Excerpt Number 75.

Commenter Name: Los Angeles Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1778
Comment Excerpt Number: 84

Comment: My name is Sofia
Carrillo. I am speaking as a member of the Coalition
for U.S. Environment in L.A. community. I have
discovered several problems with your proposal.
The amendment -- excuse me, the number of
facilities is not correct in my environmental justice
community. Your database does not link to oil
refineries near to my home that have boilers and release
hundreds of tons of air pollution every year.
Valero Oil Refinery is not on your list.
Tesoro refinery is not on your list.

Response: See response for DCN EPA-HQ-OAR-2002-0058-1778, Excerpt Number 75.

Commenter Name: Houston Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1876
Comment Excerpt Number: 117

Comment: While the NACAA and EPA data sets often
produce generally consistent results, EPA cannot exclude
from the calculation of the top performing 12 percent
the testing conducted for other compliance purposes as
required by state and local permit officials.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2841.1, Excerpt Number 9.

Commenter Name: Paul Murphy
Commenter Affiliation: CAAssociates
Document Control Number: EPA-HQ-OAR-2002-0058-1877.1
Comment Excerpt Number: 2

Comment: The carbon monoxide (CO) limits are unreasonably low -for several reasons:

According to manufacturers of calibration standards for reference materials traceable through the National Institute of Standards and Technology (NIST), the lowest concentration for CO reference material available is 5 parts per million (ppm). Based on testing procedures established by EPA through 40 CFR 60, Appendix B and Appendix F, a calibration curve should include concentrations of 30%, 50% and 80% of span. In this case, 5 ppm would represent the lowest calibration concentration point, or 30% of span. This requires that the span be set at 15 ppm. Also according to EPA's own reference methods, the span is determined as a factor (1.5 to 2) of the standard. Therefore, based on the criteria established by EPA's own reference methods, the lowest emission limit measureable that meets the calibration criteria of EPA's reference methods is between 7.5 and 10 ppm.

The test results used to determine the MACT floor should be reviewed with respect to the integrity of the calibration procedures noted in the above paragraph. EPA should throw out any of the results whose calibration procedure did not conform to the calibration criteria of the methods.

Also based on the calibration criteria of the reference methods cited above, the "zero" calibration point is acceptable if the concentration of CO is less than 1 ppm. This means that "zero" could be as high as 1 ppm. EPA is proposing emission limits that are essentially zero as a practical matter. For the data set used to determine the MACT floor, EPA should reject those results that are statistically equal to zero.

Response: EPA has made corrections to very low reported CO values, see the preamble for how EPA adjusted the CO values to consider measurement error.

Commenter Name: Fred T. Simpson
Commenter Affiliation: Scotch Gulf Lumber, LLC
Document Control Number: EPA-HQ-OAR-2002-0058-1899.1
Comment Excerpt Number: 3

Comment: There are some apparent errors in the various data sets collected as part of the Information Collection Request. EPA should stop the rulemaking until adequate data validation and analysis is completed and should re-propose the rules after this validation and analysis is complete.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2998.1, Excerpt Number 28.

Commenter Name: Chris Williams
Commenter Affiliation: Steely Lumber Company
Document Control Number: EPA-HQ-OAR-2002-0058-1875.1

Comment Excerpt Number: 3

Comment: The EPA should take the following next steps: halt the proceedings and complete an adequate data validation and analysis for all four rules.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2998.1, Excerpt Number 28.

Commenter Name: Randy Stoeckel
Commenter Affiliation: Johnson Timber Corporation
Document Control Number: EPA-HQ-OAR-2002-0058-1975.1
Comment Excerpt Number: 4

Comment: High quality data from all sources should be used in making decisions after careful review by EPA.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2841.1, Excerpt Number 9.

Commenter Name: Arlington Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1779
Comment Excerpt Number: 42

Comment: While the NACAA and EPA data sets often produce generally consistent results, EPA cannot exclude from the calculation of the top performing 12 percent the testing conducted for other compliance purposes as required by state and local permit officials.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2841.1, Excerpt Number 9.

Commenter Name: Arlington Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1779
Comment Excerpt Number: 73

Comment: As was pointed out earlier,the data that was used to set the MACT floors ignores the vast majority of boilers and emissions data that exists out there. EPA needs to consider all of the data available to set the rules and not just a select few.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2841.1, Excerpt Number 9.

Commenter Name: Arlington Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1779
Comment Excerpt Number: 84

Comment: The database used to develop the rule contained some errors. If EPA used its discretion to set reasonable limits from good data, EPA would continue to protect public health without driving industry out of business with unrealistic control requirements.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2998.1, Excerpt Number 28.

Commenter Name: Stu Philips
Commenter Affiliation: Citizen
Document Control Number: EPA-HQ-OAR-2002-0058-2122
Comment Excerpt Number: 2

Comment: The EPA failed to consider and respond to public input on its inventory, which was released just hours after the deadline for submitting public comments.

Response: See response for DCN EPA-HQ-OAR-2002-0058-1778, Excerpt Number 75.

Commenter Name: Charles Thomas III
Commenter Affiliation: Shuqualak Lumber Co., Inc.
Document Control Number: EPA-HQ-OAR-2002-0058-1758
Comment Excerpt Number: 3

Comment: In some cases, the proposed limits are based on only one or two data points and there are obvious errors in the various data points. The EPA should immediately stop the rulemaking process! The EPA needs to go back and validate the data and re-propose the rules after errors have been corrected.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2998.1, Excerpt Number 28.

Commenter Name: Jim Hickman
Commenter Affiliation: Langdale Forest Products Co.
Document Control Number: EPA-HQ-OAR-2002-0058-2065.1
Comment Excerpt Number: 7

Comment: EPA should use all of the available data and get additional data, if needed, to avoid setting limits for thousands of boilers based on data from only a few. In some cases, the proposed limits are based on only one or two data points, and there are apparent errors in various data sets.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2841.1, Excerpt Number 9.

Commenter Name: Don Grimm
Commenter Affiliation: Hood Industries, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2352
Comment Excerpt Number: 10

Comment: The emissions database includes numerous fundamental flaws that compromise the MACT floor analysis that is based on these data.
Given the limited comment period that has been provided on the Industrial Boiler MACT proposal, it simply has not been possible to conduct a thorough data quality assessment on EPA's entire emissions data base. EPA's failure to provide adequate time for an appropriate assessment of the data violates the Agency's obligation to provide a full and fair opportunity for public comment on the proposed rule. Within these severe time constraints, we conducted a spot check of 100 stack test reports and associated information from top performers in order to assess the quality of the data the Agency relied upon in calculating the MACT floors that underlie the proposed rule.

This spot check revealed numerous data errors – many of which, if corrected, would have a material impact on the stringency of EPA's calculated MACT floors and associated proposed standards. To name just a few, there was: (1) widespread inconsistency in the data reported under the Phase I and Phase II ICRs, such as entirely different methods of determining and reporting "non detects"; (2) inconsistent reporting of dioxin/furan emissions testing results; (3) inconsistent and incompatible PM emissions testing methods; and (4) mischaracterization of boiler types, such as including a coal-fired boiler in the biomass subcategory. The number and magnitude of the errors provide clear evidence that the database is fundamentally flawed and that any standard derived from the database does not have adequate factual support.

To resolve this problem, EPA must conduct a thorough review of the database, correct or eliminate the flawed data, recalculate the MACT floors and associated proposed standards, and provide a new opportunity for public comments (including sufficient time for commenters to conduct their own comprehensive review of the data).

Response: See response for DCN EPA-HQ-OAR-2002-0058-2998.1, Excerpt Number 28.

Commenter Name: Jay Galloway
Commenter Affiliation: Tolleson Lumber Company
Document Control Number: EPA-HQ-OAR-2002-0058-2452.1

Comment Excerpt Number: 2

Comment: We have carefully studied the proposed Boiler MACT rule and participated in industry discussions. We also engaged the services of consultants, so we can better understand all the implications. Based on this work we believe that there are significant flaws in the data collection, data quality, methodology and calculations when establishing the rule parameters.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2998.1, Excerpt Number 28.

Commenter Name: Lee Zeugin
Commenter Affiliation: Peabody Energy
Document Control Number: EPA-HQ-OAR-2002-0058-2730.1
Comment Excerpt Number: 2

Comment: EPA has failed to conduct a detailed review of the IB emissions data. EPA has rushed to issue a proposed rule to comply with an aggressive rulemaking schedule that EPA should never have agreed to in a consent decree. EPA does not appear to have conducted an independent quality assurance review of the data IBs submitted in response to an extensive information collection request ("ICR"). Other commenters provide numerous examples of errors in the information EPA used to identify the best performing units and to set MACT floors. EPA must conduct a thorough review of all IB emissions data before proposing MACT standards. If more time is needed to complete the MACT rulemaking, then EPA should request that time from the court.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2998.1, Excerpt Number 28.

Commenter Name: Robin Mills Ridgway
Commenter Affiliation: Purdue University
Document Control Number: EPA-HQ-OAR-2002-0058-2782.1
Comment Excerpt Number: 5

Comment: Dioxin data error needs to be corrected in Phase II ICR Database

The data included in EPA's database for dioxin emissions from Purdue's Boiler #5 (a unit tested as part of the Phase II ICR), is listed in the database incorrectly. The error in the data entry resulted in Boiler #5 being listed as one of the two top performers in the dioxin category by several orders of magnitude. The corrected data is attached. Purdue understands that the data for the other top performer for dioxin in a CFB with bituminous coal is also in error. Purdue expects that EPA will adjust the floor determination accordingly.

Response: The specified data corrections have been processed in the EPA database.

Commenter Name: Kevin Bilbrey
Commenter Affiliation: Clarke County Pole and Piling Co, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2414.1
Comment Excerpt Number: 6

Comment: EPA should use all of the available data and gather additional data, if needed, to avoid setting limits for thousands of boilers based on data from only a few. In some cases, the proposed limits are based on only one or two data points, and there are some apparent errors in the data sets.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2841.1, Excerpt Number 9.

Commenter Name: Michael Bradley
Commenter Affiliation: The Clean Energy Group
Document Control Number: EPA-HQ-OAR-2002-0058-2466.1
Comment Excerpt Number: 6

Comment: While we support EPA using all available resources to ensure full representation of the sector or subcategory, several floors proposed in this rule include data not acquired through the recent Information Collection Request (ICR). These instances are often in categories with very few data points, potentially magnifying any errors or unrepresentative situations, such as the inclusion of jet fuel in the liquid-fired category, discussed below. At a minimum, EPA should release all data included in addition to or in place of ICR data, along with their detailed test reports, to ensure full public review of any data used to establish a MACT floor.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2841.1, Excerpt Number 9.

Commenter Name: Charles R. Faulds
Commenter Affiliation: Texas Electric Cooperatives, Treating Division
Document Control Number: EPA-HQ-OAR-2002-0058-2526.1
Comment Excerpt Number: 6

Comment: EPA should use all the available data and get additional data, if needed, to avoid setting limits for thousands of boilers based on data from only a few. In some cases, the proposed limits are based on only one or two data points and there are some apparent errors in the various data sets.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2841.1, Excerpt Number 9.

Commenter Name: Kevin Bilbrey
Commenter Affiliation: Clarke County Pole and Piling Co, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2414.1
Comment Excerpt Number: 8

Comment: MACT floors should be determined on a source basis and not a pollutant by pollutant basis. EPA set the MACT floors using a small subset of data from the "best of the best" rather than the best 12% of data from all boilers as required by the statute.

Response: See preamble for response.

Commenter Name: Michael Palazzolo
Commenter Affiliation: Alcoa Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2967.1
Comment Excerpt Number: 8

Comment: Correct emissions test data for Alcoa's Warrick power plant were submitted to EPA through the ERT. However, EPA's Access database contains erroneous emissions data for Unit 3 (all test runs and all pollutants). Also, the database reports emissions for Unit 2 even though Unit 2 was not tested as part of the §114 test request. The database needs to be corrected and any emission standards should that used the Warrick power plant data should be revised accordingly.

Response: The specified data corrections have been processed in the EPA database.

Commenter Name: G. Vinson Hellwig and Robert H. Colby
Commenter Affiliation: National Assocation of Clean Air Agencies
Document Control Number: EPA-HQ-OAR-2002-0058-2841.1
Comment Excerpt Number: 9

Comment: EPA acknowledges that it did not use any of the emission test reports in state and local permit authority files and provided to it in the summer of 2008 (in the NACAA Model Rule database) in establishing its proposed MACT floors.[NACAA has formally resubmitted this data to the dockets in these rulemakings.] Instead, EPA based its calculations entirely on its "new" data set that incorporates data collected by emission sources. We believe this is a clear error that will jeopardize the final rule. We acknowledge that the subsequently collected data fills gaps that existed in the NACAA data set and do not object to EPA's use of this additional information. Incorporation of these test results in EPA's MACT floor calculations is not likely to change the calculated floor for many subcategories, but, especially considering the proposed adoption of many small subcategories, this cannot be known or assumed to be true. Exclusion of reference test results merely because they were maintained in the files of the regulatory authorities rather than those subject to regulation is arbitrary.

NACAA believes that its data set is more objective than the subsequent industry testing, since the NACAA testing was often supervised by state or local inspectors and was conducted without knowledge by the source (or the permitting authority) that the data would be used in developing emission limitations. In contrast, testing conducted as part of EPA's more recent information-gathering activities was almost universally conducted by sources who understood that it was in their interest to obtain high emission levels during the testing and was conducted without oversight by federal, state or local authorities. The regulated community was allowed to define the operating parameters for the tests.[We do not assert that there was widespread "gaming" by industry, only that there is no reason to believe that the more recent data is more credible than the information submitted by NACAA. We do note that the Office of Management and Budget (OMB) was extensively involved in the development of the test plan and that NACAA's comments respecting the test plan were largely ignored by EPA and OMB, while industry requests were accommodated. NACAA hereby incorporates its comments to EPA and OMB on the proposed testing in this comment and the administrative record in this matter] More importantly, the EPA data includes numerous entries where a source was combusting different fuel mixes, which NACAA believes will be difficult to translate into enforceable MACT limitations. While NACAA and EPA data sets often produce generally consistent results, EPA is not free to exclude from the calculation of the top performing 12 percent testing conducted for other compliance purposes as required by state and local permit officials. EPA has asserted that it does not need to consider the information provided to it by NACAA since industry sources "should" have provided this information. This assumption has not been shown to be correct and is insufficient given EPA's obligation to consider all emissions data and the relative ease of determining whether there are any NACAA-provided test results that should be included in the evaluation of the top 12 percent of performing units or any variability analyses that are conducted.

NACAA does not assert that the MACT floor calculations should be based on the data it provided to EPA in lieu of that subsequently collected by EPA, just that EPA must consider all of the emissions data available to it and not ignore the NACAA-provided information. Indeed, the EPA data fills significant gaps in needed knowledge of mercury, HCl and dioxin/furan information.

Response: In addition to the testing mentioned by the commenter, EPA conducted a comprehensive survey under an Information Collection Request. In the directions to this survey, EPA requested sources to submit the results of the most recent stack test data for each of the pollutants listed in the emission test spreadsheet by completing the spreadsheet linked below. EPA also accepted other supporting emission test data to document any earlier emission tests on the unit with similar controls and fuels as well as tests available relative to trials or tests of emission control methods or R&D efforts. The limit for requesting these tests was that the test had to reflect current operating conditions. This limit was introduced to prevent the use of older test data from units that are no longer relevant. The NACAA database does not incorporate this limit on the data so it could include CO tests on units that have since installed NOx equipment or other controls to comply with the vacated standard. It also contains many duplicates to the data reported to the ICR survey that could not be fleshed out and identified within the labeling of the units in the NACAA database. EPA has updated the initial inventory based its ICR survey data to incorporate specific comments and corrections and the current inventory of boilers resulting from the ICR supersedes previous inventories.

Commenter Name: Britt S. Fleming
Commenter Affiliation: Auto Group
Document Control Number: EPA-HQ-OAR-2002-0058-2775.1
Comment Excerpt Number: 12

Comment: The Auto Group also has significant doubts as to whether EPA has performed a thorough Quality Assurance/Quality Control (QA/QC) review of the database itself. The background document in the docket providing EPA's floor analyses for the potential Gas 1 floors in the preamble indicates that EPA included in its analysis direct-fired process heaters, which are not supposed to be included in the rule. Specifically, EPA included a direct-fired rod/bar mill furnace (CORockyMtnSteel212) among the natural gas-fired units comprising the floors for hydrogen chloride (HCl), carbon monoxide (CO), and dioxins/furans (D/F). [Footnote: See Memorandum from A. Singelton, ERG, to J. Eddinger, U.S. EPA, MACT Floor Analysis (2010) for the Industrial, Commercial, and Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants – Major Source at 143, 168, 186 (April 2010).] According to the owner and operator of the Rocky Mountain Steel unit, the unit is a direct-fired re-heat furnace where steel billet intermediate product comes into direct contact with the products of combustion. This explains why the test data for the unit shows such low CO and D/F levels. Such database errors call into question whether EPA has included the correct units in the database used to set the MACT floors in the proposal and whether EPA has undertaken the necessary QA/QC of the database.

Response: The specified data corrections have been processed in the EPA database.

Commenter Name: Stephen R. Gossett
Commenter Affiliation: Eastman Chemical Company
Document Control Number: EPA-HQ-OAR-2002-0058-3137.1
Comment Excerpt Number: 12

Comment: Significant errors exist in the database used to set CO limits for coal-fired boilers.

While we do not believe MACT standards should be set for CO based on stack test data alone (see more comments below), we believe there are significant errors in EPA's database that need correction.

For the PC boiler subcategory, EPA has made translation errors with the data for the top three performers it identified. Specifically, for the three boilers at the ILDukeEnergyTuscola facility, Units 1, 3, and 4, Appendix C-3 to the MACT floor memo shows the best stack results as 0.053 ppm CO for Unit 3, 0.0553 ppm CO for Unit 4, and 0.0571 ppm CO for Unit 1. All these values were derived from the EPA' Access database that has the reported data expressed as ppb instead of ppm. This error needs correction and the MACT floor analyses for new and existing units should be redone.

Response: The specified data corrections have been processed in the EPA database.

Commenter Name: Jack Carter
Commenter Affiliation: Weyerhaeuser Company
Document Control Number: EPA-HQ-OAR-2002-0058-2797.1
Comment Excerpt Number: 30

Comment: Four Weyerhaeuser wood products mills were selected to participate in the "Phase 2" stack testing portion of EPA's Information Collection Request survey implemented under the CAA §114. Upon review of EPA's final database a number of errors have been identified in the test report data submitted to EPA for three of the sites. The fourth site is no longer in Weyerhaeuser ownership, and we understand the boiler is not in operation by the new owner. Corrections to these data and a limited set of "Phase 1" data have been submitted to EPA (to the attention of Mr. Brian Shrager, USEPA, and to EPA's data contractor, ERG, at its website). [See submittal for Exhibit 1 showing an email specifying corrections to facility emissions data.]. Copies of the submitted corrections are included as an attachment to these comments so that they are included in the docket.

Response: The specified data corrections have been processed in the EPA database.

Commenter Name: Britt S. Fleming
Commenter Affiliation: Auto Group
Document Control Number: EPA-HQ-OAR-2002-0058-2775.1
Comment Excerpt Number: 30

Comment: Work practices are More Appropriate for Boilers/Process Heaters Using Landfill Gas and Fit with the Criteria for Section 112(h) Work Practices.

Despite the fact that three of EPA's five proposed HAP floors (particulate matter (PM), mercury (Hg), and D/F) for the Gas 2 subcategory include data from a single landfill gas unit (BMW), EPA's data for landfill gas units are not accurate and do not reflect what is achieved in practice by these sources. For example, there appears to be an error in the Hg data for the BMW unit. The error seems to result from not including the detection limits for undetected values when summing the five different analytical fractions for the Method 29 sampling train. EPA specified in the guidelines for the ICR that detection limits should be included in the data sums submitted to EPA. The lab analysis report for the BMW unit for Method 29, however, shows total mercury catches which include only the detected value in the HCl rinses. If summing detection limits with the detected values following EPA guidelines for the tests, the total mercury catches would be approximately four times higher. This would result in a much higher Hg floor for the Gas 2 subcategory. [Footnote: BMW will be submitting revised Hg information to EPA in a separate letter.]

Response: The specified data corrections have been processed in the EPA database.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 48

Comment: Emission test results for filterable particulate matter, mercury, HCl, CO, and dioxin/furan are the underlying basis for the proposed emission limits. In 2008, EPA distributed a survey targeted at 'major' (with respect to hazardous air pollutants) sources. This survey was intended to gather information on individual boilers and process heaters. Respondents were also asked to submit summaries of available emission test and fuel analysis results using spreadsheets. A database was created from the spreadsheet submissions and it was used to assess the need for additional data to support the Boiler MACT rulemaking.
In 2009, a second ICR mandated extensive stack testing and fuel analyses at roughly 150 boilers and process heaters. EPA selected these units to fill perceived information gaps in the database and to obtain additional test data from numerous 'best performing' units to examine emissions variability. Companies were given only four months to conduct this testing and submit the results to EPA.
A combined Microsoft Access emissions database with the 2008 survey responses and 2009 testing program results was first released in January 2010 and then revised in February 2010, March 2010, and April 2010 ("Emissions Database for Boilers and Process Heaters Containing Stack Test, CEM, & Fuel Analysis Data Reported under ICR No. 2286.01 and ICR No. 2286.03, Version 5). Revisions were made to incorporate late-arriving results from the second ICR, delete information from units that had ceased operation, correct data that had been entered into the database from faulty output from EPA's Electronic Reporting Tool (ERT), adjust dioxin/furan test results, and correct miscellaneous reporting inconsistencies and other problems.
The file size for Version 5 of the database is about 110 MB. It contains 44,389 records with emission test results; 92,822 records with fuel analysis information; and 44,219 records with CEMS data. Although this is a massive amount of information, the emissions data in the database being used to set these standards that will impact thousands of sources should be checked by EPA for accuracy.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2998.1, Excerpt Number 28.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1

Comment Excerpt Number: 49

Comment: Over the past several months, the National Council for Air and Stream Improvement (NCASI) [Footnote: The National Council for Air and Stream Improvement (NCASI) is an independent, non-profit research institute that focuses on environmental topics of interest to the forest products industry.] has examined about 100 stack test reports and associated laboratory analysis reports for filterable particulate matter, dioxin/furan, mercury, HCl, formaldehyde, and/or total hydrocarbons (THC). Most of these reports were for boilers assigned to either the biomass or coal subcategories, and most were listed in the Version 5 (or earlier versions) database as being among the units with an emission test in the lowest 12% for filterable particulate matter, dioxin/furan, mercury or HCl. NCASI found a disturbing number of problems with the test results appearing in the Version 5 database for these so-called ‘best performing’ boilers. It was obvious the test results being used to develop the proposed emission limits had not received an adequate review. Some of the problems identified by NCASI, when corrected, will have a dramatic impact on the proposed emission limits. It is imperative for EPA to thoroughly review all of the available data for the top performing units before promulgating emission limits. We identify several data quality problems that should be corrected throughout these comments, and many of our member companies have submitted requests for data corrections to EPA.
The most critical shortcoming in EPA’s data analysis is merging test results reported by 2008 survey respondents with test results from the 2009 mandatory test program into a single database that was used to identify ‘best performers’ in each subcategory and calculate emission limits. EPA implicitly assumed they were equivalent in terms of quality without conducting a detailed review of the actual stack sampling and associated laboratory analysis reports.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2998.1, Excerpt Number 28.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 54

Comment: There are many other problems in Version 5 database caused by lack of adequate review of stack sampling and associated laboratory reports. The following are examples of problems with ‘top performer’ emissions data for the biomass subcategory:
* ARGBPMorrilton – Unit SN-04 conducted stack tests in 2009 as part of the Phase II ICR. EPA’s database lists the dioxin/furan test result as being the lowest TEQ value for the biomass stoker subcategory. Individual dioxin/furan congeners are not in the database with the exception of the “total congeners” such as Total OCDD. All congeners preceded by numbers are absent from this boiler’s dioxin/furan dataset. Since the total TEQ is based on the sum of the individual congener TEQs, the total used for ranking this boiler is incorrect.

* WAWeyerhaeuser_Raymond – Hog Fuel Boiler EU-1 conducted stack tests in 2009 as part of the Phase II ICR. EPA’s database lists the dioxin/furan test as being the lowest TEQ value for the biomass fuel cell subcategory. For this boiler, “total” congener data are entered as “other.”

Further only three congeners preceded by numbers are provided in the database. The boiler owner may have submitted mislabeled data to EPA, but EPA should be able to construct a relatively simple query to find instances of this problem.

* ORWeyerhaeuserCoWarrentonLumberMill – Boiler 3-HFB conducted stack tests in 2009 as part of the Phase II ICR. EPA’s database lists the dioxin/furan test as being the third lowest TEQ value for the biomass fuel cell subcategory. Three dioxin/furan sample runs were conducted. Sample runs 1 and 3 failed almost all the quality assurance criteria. These two runs do not appear in the database. Run 2 also had very poor quality assurance values but did contain some ‘passes.’ EPA put the congeners that passed the QA into the database. Since not all congeners were entered, the sum of the TEQs is biased low (based on an incomplete dataset). Neither the testing contractor nor the lab that analyzed the samples were able to determine the cause of extremely low recoveries that resulted in two failed runs and one run with extremely poor quality results. Given the uncertainty about these tests, EPA should not include any of the results from these tests in its database.

* ARWeyerhaeuserDierksMill – Boiler SN-45 conducted stack tests in 2009 as part of the Phase II ICR. EPA’s database lists the dioxin/furan test as being the fourth lowest TEQ value for the biomass fuel cell subcategory. In the EPA database, the congener “1,2,3,7,8 PeCDD” has duplicate values for both Sample Run #2 and Sample Run #3, the congener “1,2,3,7,8,9 HxCDF” has duplicate values for both Sample Run #1 and Sample Run #2, and there are 11 other congeners that have duplicate Sample Run #2 data.

* GAGPCelluloseBrunswick, U700-No. 4 Power Boiler - This boiler is ranked No. 1 in EPA’s list of best performers for filterable PM emissions for the biomass subcategory. Data from two separate testing events for this source are in EPA’s boiler MACT database – a Phase I test conducted in November of 2007 and a Phase II test conducted in August of 2009. The Phase II data are based on EPA’s OTM 27 particulate method for measurement of filterable PM10 and PM2.5. Given that EPA Method 5 was specified as the method to use for measurement of filterable PM within EPA’s test plan for Phase II boiler MACT testing, and that OTM 27 uses an in-stack unheated filter versus Method 5’s heated out of stack filter, and that NSPS performance standards for filterable PM are based on EPA Method 5, it is inappropriate to use the filterable PM data from the OTM 27 test results. EPA Method 5 results were included in the Phase II report and should be used instead. EPA’s database lists filterable PM emissions of 0.0002, 0.0009, and 0.0005 lb/MMBtu for the OTM 27 runs one through three, respectively. This is in contrast to the Method 5 results in the same report of 0.0070, 0.0075, and 0.0035 lb/MMBtu for runs one through three, respectively.

* ORGeorgiaPacificWaunaMill, EU35-Fluidized Bed Boiler – This boiler is ranked No. 2 in EPA’s list of best performers for filterable PM emissions in the biomass subcategory. Data from two separate testing events for this source are in the Version 5 database – a Phase I test conducted in March of 2006 and a Phase II test conducted in July of 2009. Data from the Phase I test are based on Oregon’s particulate matter method ODEQ5. The Phase II data are based on EPA’s OTM 27 particulate method for measurement of filterable PM10 and PM2.5. For the same reasons stated earlier, it is inappropriate to use filterable PM data generated using OTM 27 for establishing boiler MACT floors.

* WAGraysHarborPaper, No. 6 Boiler (EU2) – This boiler is ranked No. 12 in EPA's list of best performers for HCl in the biomass subcategory on the basis of a 2009 stack test. However, EPA did not recognize that two stacks were tested and that the total boiler emissions should be the sum of the two tests. Approximately 80% of the boiler flue gas is directed to only a multiclone, and 20% is directed to a secondary multiclone followed by a packed bed venturi scrubber. These gas streams are later sent to a stack which also services another biomass boiler (EU1). The EPA database treats these as two separate tests, with the one on the venturi scrubber being much lower (0.0002 versus 0.025 lb/106Btu). A 2006 test is also in the EPA database, with an average of 0.045 lb/106Btu. This test appears to include both portions of the flue gas.

* LAGPPortHudson, EQT0109-No.6 CFB Boiler – This boiler is listed as a top performer in the biomass subcategory for filterable PM on the basis of a 2007 test with only two runs. This boiler should not be in the biomass subcategory since it was burning petroleum coke at the time of the test. In the Phase I survey, the emission test template drop-down fuel menu does not list petroleum coke, which could be the source of confusion. Because the 2007 test report was not reviewed by EPA, this discrepancy was not detected and it was assumed coke oven gas was the correct entry.

* MTPlumCreek, Wellons Plywood – This unit is listed as a top performer for HCl in the biomass subcategory on the basis of a 2009 test. The Wellons Plywood unit combusts biomass and the flue gas from the burners is directed to a plywood veneer dryer. An ESP follows the dryer, and the stack test was conducted at the ESP exit. It seems that this unit is neither a boiler or process heater (as defined in the proposed rule), since the flue gases come into direct contact with the material being dried. It appears this unit was initially mischaracterized and then mistakenly selected for Phase II sampling. A review of the stack sampling report would have uncovered this problem, but apparently the source description section of the report was not examined. All data for this unit should be removed from the EPA Boiler MACT database.

* GATempleInlandThomson, BW-B001. This unit has the lowest EPA Method 10 test for CO in the biomass stoker subcategory and thus CO test data for this unit are the basis for the new source limit for stokers, and are part of the MACT floor pool for existing biomass stokers. The Version 5 database lists BW-B001 as "Stoker/Sloped Grate/Other". The January 2009 Phase I survey database indicates a "True" in the columns labeled watertube, package, and wall-fired in the Unit Design/Operation table; all other columns pertaining to the BW-B001 description are "False". There is an obvious inconsistency between the two databases. Contacts with company personnel indicate the boiler is designed to fire sanderdust, natural gas, and distillate oil, and should be classified as a suspension burner.

The above examples are limited to the EPA-identified "top performers" in the biomass subcategory. Once EPA conducts its reviews of the reports for these units and revises its emission database, many will no longer be "top performers". They will be replaced by other units, and EPA will need to carry out reviews of additional reports to insure the quality of data being used to set the emission limits.

Response: The specified data corrections have been processed in the EPA database.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 55

Comment: The following are a few issues identified in Version 5 database with some of the EPA-selected top performers in the coal and liquid subcategories:
* SCSonocoHartsville – Boiler 9 - conducted stack tests in 2009 as part of the Phase II ICR. EPA's database lists the dioxin/furan test result as being the lowest TEQ value for the coal fluidized bed subcategory. Individual dioxin/furan congeners are not in the database with the exception of the "total congeners" such as Total OCDD. The TEQ is thus based only on OCDD and OCDF, and is thus approximately two orders of magnitude too low.

* SCCogenSouth – B001 Main Boiler – This unit is listed as best performer for mercury in the coal subcategory based on a 2009 test. The EPA database has front-half and back-half results for three Method 29 runs. With the exception of Run 3 back-half, all are listed as ND. There is also a total listed for each run, but the totals are not listed as ND. Furthermore, mercury fractions below laboratory minimum levels were treated as zeroes when the totals were calculated. Rather than the three run average of 0.17 lb/1012Btu, a value of <0.51 lb/1012Btu should have been reported for the 2009 test. The EPA database also contains 2003, 2005, and 2007 mercury test results for this boiler. For each of these Method 29 tests, the total mercury emissions were calculated assuming a zero value for fractions that were below the laboratory detection limits. Thus all mercury data in the EPA database must be corrected.
* MNGPDULUTH EU33 Boiler #3 is listed in the EPA database as the lowest emitting liquid fired unit for mercury emissions. An examination of the two sets of test data for this unit revealed that non-detect fractions of mercury were treated as zero, biasing the results low. The test runs were only 2 hours long for one set of test data and only 3 hours long for the other set of data. The mercury data for this unit should be reviewed and either corrected or removed from the database.
* The October 20, 2009 report for the August 24-27, 2009 testing conducted at IAADMCornProcessingCR EU-501B indicates that all fractions of mercury were not analyzed and reported, which biases the results low.
* The SCMilliken-Dewey D30 boiler firing anhydrides waste (a unique boiler in the data set that is not representative of any other liquid-fired boiler) is a top performer for several compounds in the liquid subcategory. A review of the test report for the August 2009 testing indicates that non-detects were treated as zero or half the detection limit, which does not comport with EPA's Phase 2 ICR testing guidance and biases the results low. The emissions results for this boiler should be re-calculated.
* A review of the August 28, 2007 test report for MITBSimonPowerPlant Unit 2 indicates that the lab listed high sulfur in the samples as a possible interferent to the Method 29 analysis. The lab report also does not show receipt of all sample fractions. A review of the October 15, 2009 test report (same testing firm) for IAUofIowa EP7 Boiler 11 shows the same concerns. The data in these reports should be more closely examined to determine if it is valid.

* TX Equistar Chemicals UTBLRG CO data: The values reported were the uncorrected CO concentration and the unit of measure was incorrectly picked as “ug/dscm @ 3% O2” on the survey form. The correct unit of measure selected should have been ppmv @ 3% O2. The correct test average is 3.39E+01 ppmv @ 3% O2.
* For Units 1, 3, and 4 at the ILDukeEnergyTuscola facility, Appendix C-3 to the MACT floor memo shows the best stack results as 0.053 ppm CO for Unit 3, 0.0553 ppm CO for Unit 4, and 0.0571 ppm CO for Unit 1. These values were derived from the EPA’s Access database that has the reported data expressed as ppb instead of ppm, skewing the CO floor for pulverized coal boilers too low.

* IDTASCOPaul Unit 2 is a top performer for HCl in the coal subcategory. The unit has a wet scrubber. For the June 2006 emission test, the 3 test runs averaged 3.85E-5 lb/MMBtu with all 3 values being non-detect. EPA collected no coal chloride variability data for this unit. As the values being used in the floor analysis are below detection limits, these values should be adjusted upward to reflect a measurable value. Further variability should be accounted for with coal chloride content data.

* InAlcoaWarrick Units 2 and 3 are top performers for HCl and Unit 3 is a top performer for mercury in the coal subcategory. However, only 2 test runs are included for each boiler in the floor calculations. As two test runs do not constitute a valid emissions test and do not demonstrate emissions variability sufficiently, this data should not be included in the floor calculations.

* VAINVISTAWaynesboro Unit 2-205 (V#1) Vaporizer #1: This unit is a liquid subcategory top performer for HCl. It is a No. 6 Oil fired Dowtherm® Vaporizer (process heater) with a design heat input of 43MMBtu/hr. The 2008 emission test is listed as having averaged 0.000243 lb/MMBtu. The unit is listed in the EPA database as having a fabric filter, which is not the case - it has no control. Most likely the data for this unit has been confused with the facility’s PC fired Boiler 2, which does have a fabric filter. No fuel quality data is provided for this unit. The Vaporizer 2 emission test showed HCl emissions of 0.05 lb/hr. If operated at 43MMBtu/hr heat input, that would be 0.0012 lb/MMBtu. It is likely the heat input used to calculate the listed lb/MMBtu emission rate was also confused with Boiler 2 heat input of 168MMBtu/hr during its test (the emission test spreadsheet gives steam output for the vaporizer during those tests of 166.04, 166.1, and 167.37 Mpph, which is not applicable to a vaporizer). Therefore, the reported and utilized emission rate for this unit is too low.

* ILCognisCorp Boiler 2 is ranked #2 in the liquid subcategory by EPA based on the chlorine in the fuel (this unit is also a top performer for Hg). This unit is a 1948 vintage field erected watertube boiler with a design heat input of 67.3MMBtu/hr. Both Boilers 1 and 2 at this facility fire natural gas and waste vegetable oil as fuel per the emissions test report. All fuel analyses for this company are listed as animal fats/tallow or vegetable oil. (No analyses are provided for fuel oil). Twelve liquid analyses are provided, with Cl ranging from 0.036% to 0.13%, and HHV ranging from 13,900 to 21,300 Btu/lb. EPA listed equivalent HCl emissions for that unit as 4.74E-6 lb/MMBtu; however the EPA calculation is not correct. For example, the analysis at 0.078% and 19,100 Btu/lb is shown by EPA to be 4.4E-6 lb/MMBtu, but calculation by Cl percent and Btu/lb and 36/35 for HCl/Cl MW gives 0.042 lb/MMBtu. This type of calculation

error applies to all of that unit's analyses and emission rate calculations. The correct average equivalent HCl emission rate based on the fuel analysis data and 100% emission of chloride as HCl is 0.045 lb/MMBtu. This emission rate would put this unit above all others in the database, not in the top performers. In addition, emissions test data for Boiler 1 was provided for testing conducted during the time the liquid analyses were provided indicating an HCl emission rate of 0.005542 lb/MMBtu, ranking #186 in the EPA MACT Floor list. Fuel firing during that test consisted of 80% light liquid and 20% natural gas. Thus, while natural gas co-firing would be expected to dilute the HCl emission rate leading to lower HCl emissions, even the measured emission rate is three orders of magnitude higher than the EPA listed fuel equivalent emission rate. So there are a number of problems with this unit being used as a top performer: a) Waste vegetable oil is in no way representative of all liquids fired in units subject to the rule, and certainly is not representative of fuel oils, b) the EPA determined fuel equivalent HCl emission rate is incorrect (erroneously low), and c) the reported emission data for one of the units while cofiring the waste vegetable oil with natural gas places the unit as a worst performer. This unit's data should be corrected and it should not be among the top performers in the liquid subcategory because the fuels being fired are not representative of the majority of the units in this subcategory and are not widely available.

* MEFPLEnergyWyman Unit #5 is listed as a top performer for mercury in the liquid subcategory. It is a 1977 vintage firetube boiler burning No. 6 fuel oil with no controls. The average equivalent Hg content based on fuel sample analysis is 29.6 lb/TBtu. However, the emission rate per emissions test average is identified as 0.086 lb/TBtu. As there is a tremendous difference between apparent oil Hg level and emissions test level and this unit has no control device, EPA should quality assure the fuel and test data.

* For several of the listed liquid subcategory top performers, the fuel analyses for Hg indicated Hg contents below detection levels (NJVinelandMuniElectric-HowardDown- Unit 9, SCMilliken-Dewey- D30, NYConEd59thStStationNewYork- Boiler 118, PABoeingRidleyPark-033, ILCognisCorp- Boiler #2 & #1, INUSSteelGaryWorks- O4B10459). Use of data from boilers firing fuels with no detectable Hg content to set emission limits for all liquid-fired boilers is not appropriate. If EPA continues to use these data, they should at least be adjusted upward to represent a measurable quantity.

* PAConemaughPowerPlantNewFlorence Aux Boiler B is listed as a top performer for PM in the liquid subcategory. Emission test results for the 3 runs were 0.0013, 0.00032, 0.001 lb/MMBtu. Without the test report there is no way to identify if there were issues with the second run that led to significantly lower emissions than the other two runs, but we question the validity of the second run. For comparison, the other auxiliary boiler at the site, a similar size unit, showed PM emissions of 0.009, 0.0087, 0.0047 lb/MMBtu for an average of 0.0075 lb/MMBtu, much more in line with Runs 1 and 3 for Boiler B. EPA should investigate the validity of the Boiler B data.

* NJSunocoWestville Boilers #5, #6, #7, #8 are top performers in the liquid subcategory. However, it was publicly reported that this refinery was shutdown in 2009, so these boilers should be removed from the database.

* NENebraskaCityStation Auxiliary Boiler 2 is listed as a top performer for CO in the liquid subcategory. EPA lists average CO emissions of 0.2733 ppm @3% O2 dry, which is the average of the 3 reported runs. Per the emissions test report, it appears the NDIR analyzer was set up with a 1000 ppm span, with upscale calibrations between runs using 229 ppm CO cal gas. Therefore, at best the M10 accuracy specification of +/- 5% of span would allow for an accuracy of +/- 11.45 ppm CO. Thus, the reported data from this test indicating 0.27 ppm is well below the potential accuracy limitations of the methods used.

* OHOSUColumbus B140 is listed as a top performer for CO in the liquid subcategory. EPA lists average CO emissions of 0.54434 ppm @3% O2 dry, which is the average of the 3 reported runs, however 2 of those were reported at < 0.5 ppm (DL). The M10 analyzer was used with a 100 ppm calibration span. The reported results appear lower than the M10 accuracy specification warrants for use in establishing a MACT Floor.

* NCCampLejeuneMCB C-CG-650-83B and 84B are listed as top performers for CO in the liquid subcategory. EPA lists average CO emissions of 0.8667 and 0.5667 ppm @3% O2 dry for 83B and 84B, respectively, which are the average of the 3 reported runs for each boiler firing No. 2 Oil. The M10 analyzer was used with a 246 ppm calibration span. The reported results appear lower than the M10 accuracy specification warrants for use in establishing a MACT Floor.

* VADominionPossumPoint Aux. Boiler 001 is listed as a top performer for CO in the liquid subcategory. EPA lists average CO emissions of 0.6286 ppm @3% O2 dry, which is the average of the 3 reported runs. However, the emission test report indicates that the boiler fired natural gas during the emissions testing; therefore, this unit is not appropriate to include for setting a liquid fired unit MACT Floor.

* PAKeystonePowerPlantShelocta Aux Boiler A is listed as a top performer for CO in the liquid subcategory. EPA lists average CO emissions of 0.7590 ppm @3% O2 dry, which is the average of the 2 reported runs. The M10 analyzer was used with a 149 ppm upscale calibration span gas. The reported results appear lower than the M10 accuracy specification warrants for use in establishing a MACT Floor.

* WINewPageKimberly Boilers 21 and 22 burn coal and share a common stack. They are not currently listed as top performers in the coal subcategory. However, their mercury data in the database are 1000 times higher than the actual test data. The data should be 1.74E-06, 1.56E-06, and 1.88E-06 lb/MMBtu (the data are listed as 1.74E-03, 1.56E-03, and 1.88E-03 lb/MMBtu).

Response: The specified data corrections have been processed in the EPA database.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 56

Comment: For some test reports, the analytical data are not provided, so we are unsure whether the data were reduced appropriately and we cannot determine whether non-detects were treated at the detection limit. EPA should use only test data that can be verified.

Response: See response to DCN EPA-HQ-OAR-2002-0058-3213.1, Excerpt Number 68.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 57

Comment: We have noted that there are several boilers, some listed as top performers, that have been mis-categorized:
* LAShellChemicaGeismar Furnace F-S801 is not a Gas 2 boiler, but should be categorized as a liquid boiler because it burns heavy recycle.
* WIGPGreenBay2818 B10 - Wastepaper Sludge-Fired Boiler 10 is not a liquid-fired boiler. This boiler burns secondary fiber deinking residuals to produce steam for the secondary fiber papermaking process. Secondary fiber deinking residual is a biomass fuel consisting of recovered fiber from the deinking process that cannot be made into paper. Fuel analysis data for 2007-08 indicates an average deinking residual HHV of 2575 Btu/lb (4400 Btu/lb dry), with moisture of 42%. Similar analyses for 2009 indicate a moisture content of 41% and a dry HHV of 3875 Btu/lb. Therefore this unit should be included in the biomass category.
* LAGPort Hudson - EQT0109 No. 6 CFB is listed as a biomass boiler. This boiler burns more than 10% petroleum coke along with biomass and some natural gas to make steam for the papermaking process. The probable reason for this boiler being mischaracterized is that during EPA's Phase I Information Collection Request (ICR) there was no choice in the drop down menus for petroleum coke and the instructions told responders to select coke oven gas instead. Therefore, this boiler should be in the coal category since it burns more than 10% petroleum coke.
* The following boilers also have been listed as burning coke oven gas when in fact they burn petroleum coke:
GASRMRincon – EU B002: This boiler is incorrectly listed in the Gas 2 category but should be listed in the coal category because it burns 100% petroleum coke but does not burn coke oven gas.
GASRMRincon – EU B003: This boiler is correctly listed in the coal category and burns a combination of coal and petroleum coke, but does not burn coke oven gas.
GASRMRincon – EU B001: This boiler is correctly listed in the coal category and burns a combination of coal and petroleum coke, but does not burn coke oven gas.
WIGPGreen Bay0218 – B29-Fludiized Bed Boiler #9: This boiler is incorrectly listed in the Gas 2 category but should be listed in the coal category because it burns 100% petroleum coke but does not burn coke oven gas.
We suspect that there are many other boilers in the database that have not been placed in the correct subcategory and are inappropriately influencing MACT floors.

Response: The specified data corrections have been processed in the EPA database.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 58

Comment: EPA must scrutinize the emission test database for potential problems with units having multiple tests where a top performer may not be identified because of inappropriate grouping of test runs. Two such examples in the biomass subcategory follow:

* MESDWarrenSomerset, No.2PowerBoiler – EPA improperly grouped sample runs creating substantial differences in test event averages for filterable particulate matter. A two run set (4-14-08) and a four run set (4-21-08) were treated as two three run sets. For one of the two sets the average value should be more than twice the current value.
* FLRayonierPerformance, PB06 – The boiler was tested in 2008 with three fuel mixes. Two sample runs were conducted per fuel mix. These six runs should represent three test events. EPA grouped the data as two three run sets (dioxins/furans and perhaps other pollutants).

Response: The specified data corrections have been processed in the EPA database.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 60

Comment: It is noted that a wet ESP was installed in 2007 on this boiler, so it is appropriate to segregate test data gathered before and after installation of this device. However, the control device listed in the Version 5 emissions database is a wet ESP for all test dates, which is not accurate.

Response: The specified data corrections have been processed in the EPA database.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 68

Comment: NCASI also conducted detailed reviews of the 2009 ICR test reports for several boilers. One component of that review was the handling of reporting of measurements below the

method detection limit (or reporting). Due to lack of an EPA procedure of determining the detection limits in EPA Method 29, the data included in EPA's database and used to set the MACT emission standards includes a significant amount of data reported using the reporting limits. The overall range of the DLs/RLs for the sources reviewed was from 0.047 to 0.84 µg, which represents a factor of 20.
This analysis once again highlights the need for detailed report review and using consistent data prior to utilizing the data for setting the standards.

Response: EPA incorporated data updates based on many of the NCASI findings in the test reports. EPA also conducted an independent review of 4 test reports from low emitting sources to evaluate whether all mercury fractions were treated appropriately.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 152

Comment: The boilers at FLUSSugarCorp, FLOsceolaFarms and FLSugarCaneGrowersCoop (except Boiler No. 1) are all listed as spreader stokers. Boiler No. 1 at FLSugarCaneGrowersCoop is listed as Other – water-cooled pinhole grate. The CO information from these boilers should be put in the appropriate subcategories. The dioxin/furan information for WAGraysHarborPaper No. 6 Boiler and ORRosboroSpringfield DV 01.1 should be in the Dutch oven subcategory and that for ORFlakeboardEugene Boiler-2 in the suspension burner subcategory.

GATempleInlandThomson BW-B001 is listed as a stoker/sloped grate/other in the Version 5 emissions database, but as a package watertube wall-fired boiler in the survey database. This unit burns sanderdust, natural gas, and distillate fuel oil, and should be in suspension burner subcategory.

Response: The specified data corrections have been processed in the EPA database.

Commenter Name: Lewis F. Gossett
Commenter Affiliation: South Carolina Manufacturers Alliance
Document Control Number: EPA-HQ-OAR-2002-0058-2602.1
Comment Excerpt Number: 2

Comment: An analysis of the database used by the EPA to arrive at the proposed regulation shows that the database is fundamentally flawed and that any standard derived from the database does not have adequate factual support.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2998.1, Excerpt Number 28.

Commenter Name: Mary Graham
Commenter Affiliation: Charleston Metro Chamber of Commerce
Document Control Number: EPA-HQ-OAR-2002-0058-2732.1
Comment Excerpt Number: 11

Comment: EPA has both the need and the opportunity to make significant changes to the proposed Industrial Boiler MACT. These changes are needed to correct fundamental technical and data quality issues that compromise the validity of the proposed standards.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2998.1, Excerpt Number 28.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-2702.1
Comment Excerpt Number: 12

Comment: EPA did not make MACT floor memo Excel files available in the docket for the Boiler rule until 3 weeks into the original 60-day comment period.

The rules would also benefit significantly from the generation of additional emissions information. EPA's MACT Floor tables indicate that eleven of the thirty MACT Floor emission limitations for existing sources were determined using less than five sources due to a lack of available data.6 No time was allocated for additional data-gathering.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2841.1, Excerpt Number 9.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 33

Comment: The database used for this rulemaking is rife with anomalies due to apparently erroneous identification of fuels fired, equipment type, incorrect conversion of reported results to standardized units and data transcription and import errors, reporting errors, and other issues. Therefore, the quality of the data in EPA's database is inappropriate for use in setting emission standards of any kind, much less national standards affecting hundreds to thousands of individual units. Many of these issues could be resolved simply by reviewing all of the information provided to EPA via the ICR such as primary data (field data, laboratory reports, etc.) submitted with test reports and resolving anomalies via communications with the facility. In Attachment A, we list many specific anomalies identified during our review; this list is not comprehensive, but indicative of the types of issues encountered during our review. In several cases, the source of the anomaly was identified, confirmed via contact with the facility and correction action was identified. This section focuses on anomalies in the data used by EPA. In Comment VI.B.1 we discuss the failure of this data to properly represent the source category.

Recommendation: Since the rule impact is so extreme, the Agency should verify every entry, individually, with the boiler or process heater owner/operator and against the test report or CEMS output to validate all of the data used in this rulemaking. At a minimum, every data point for units in the floor and all data in small data sets (e.g., <30 units) should be individually validated. All anomalies identified in Attachment A and in comments of others must be resolved.

Response: The specified data corrections have been processed in the EPA database.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 35

Comment: * The database contains entries that are improbably high for gas fuels (e.g., CTCytecWallingford 150 Furnace dioxins/furans results, which are over-reported because detection limits are mis-reported as total mass rather than in-stack concentration).

Response: The CTCytecWallingford dioxin/furan data have been noted as improbably high in the EPA database and will not be used in future analyses.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 36

Comment: * The database contains entries for gas-fired units that indicate the use of emission controls that typically are not used with clean gas fuels (baghouses, scrubbers, etc.), strongly suggesting these units may be improperly assigned to the gas fuel subcategories (e.g., GAGPSRMRiincon EU B002, which is petroleum coke fired).

Response: The specified data corrections have been processed in the EPA database.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 37

Comment: * The database contains data for units that are excluded from the proposed rule. For instance, 63.7491(j) excludes blast furnace gas-fired boilers and process heaters, but such units are included in the database.

Response: Blast furnace units co-firing with other fuels are covered under this standard. There are no units firing 100 percent blast furnace gas that are used as a basis of the floor calculations.

Commenter Name: Leonard W. Sandridge
Commenter Affiliation: University of Virginia
Document Control Number: EPA-HQ-OAR-2002-0058-2769.1
Comment Excerpt Number: 38

Comment: We reviewed UVA data (Facility ID = VAUniversityofVirginia) in the survey database and noticed the following omissions or inconsistencies:

Data: Control Device Table
* 5575-1-01, 5575-1-02, 5575-1-03, and 5575-1-04 were omitted. These boilers are all equipped with low NOx burners.
* Boilers 7103-1-03R and 7103-1-04R were omitted. These boilers are equipped with low NOx burners and flue gas recirculation (FGR).
* In addition to the controls noted in the database, our coal boilers 7103-1-01R, 7103-1-02R, and 7103-1-05 control NOx emissions using over-fire air and FGR when firing coal and low NOx burners and FGR when firing natural gas.

Data: Emission Test and CEMS Installed Table

The following boilers were included in our survey but were omitted from this data table:
* 0207-1-01, 0231-ICU-01, 0580-2-01, 0603-1-01, 5576-1-01, 5575-1-01 though 5575-1-04, 5576-1-02, 5577-1-01, 7103-1-03R, 7103-1-04R, 7533-1-01, and 7533-1-02.
* Unit ID 2116-ICU-01 should be replaced with the correct numbering 2616-ICU-01.
* The “CO Test” and “PM Test” columns for 7103-1-01R, 7103-1-02R, and 7103-1-05 indicate False, while we submitted CO and PM test data.

Data: Emissions Test Background Info Table

* Boilers 5575-1-01 through -04 are equipped with low NOx burners; currently the “Standardized Control Device” column indicates no equipment.

* Boilers 7103-1-03R and 7103-1-04R are equipped with low NOx burners and FGR; currently the “Standardized Control Device” column indicates no equipment.
* For Boiler 7103-1-01R with a test date of 12/5/07, Boiler 7103-1-02R with test date of 1/15/04, for Boiler 7103-1-05 with test date of 4/2/08, only natural gas was fired. When only natural gas is fired, the control devices used are low NOx burners and FGR. No other controls are used but the “Standardized Control Device” column indicates otherwise.
* All other test dates for Boilers 7103-1-01R, 7103-1-02R, and 7103-1-05 involved firing coal. The control devices used include overfire air, FGR, cyclone, spray dryer, and baghouse. All or some of these controls are omitted from the “Control Device” and “Standardized Control Device” columns.

Data: Emissions Test Fuel Data Table The heat input data in the “Standardized Fuel Rate” column for all Boiler 7103-1-05 test runs and Boiler 7103-1-01R December 2007 test runs are noticeably lower than the values we provided in our questionnaire.

Data: Regulatory and Permit Limits Table

All of our boilers, except those at our main heat plant (7103-1-01R through 7103-1-05) have one set of emission limits in our state air permits. Depending on the pollutant, the limit is baesd on calculated from AP-42 emission factors for either natural gas or distillate oil combustion, whichever is higher for our gas/oil boilers. In the survey, we indicated which fuel the limit was based on, but the limits are applied irrespective of the fuel burned. This may not be how the question was intended to be answered.

Our main heat plant boilers have discrete emission limits for each fuel burned (natural gas, distillate oil or coal). We provided all these emission limits in our survey, but not all of the emission limit-fuel combinations were imported to the database.

Response: The specified data corrections have been processed in the EPA database.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 43

Comment: As demonstrated by the large number of mis assignments listed in Attachment A, it is clear the data doesn‘t adequately indicate which of the proposed subcategories a particular unit should be assigned.

Response: The specified data corrections have been processed in the EPA database.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-2702.1
Comment Excerpt Number: 66

Comment: CIBO also doubts whether EPA has performed a thorough Quality Assurance/Quality Control (QA/QC) review of the database itself. The background document in the docket providing EPA's floor analyses for the potential Gas 1 floors in the preamble indicates that EPA included in its analysis direct-fired process heaters, which are not supposed to be included in the rule. Specifically, EPA included a direct-fired rod/bar mill furnace, CORockyMtnSteel212, among the natural gas-fired units comprising the floors for HCl, CO and D/F. According to the owner and operator of the Rocky Mountain Steel unit, the unit is a direct-fired re-heat furnace where steel billet intermediate product comes into direct contact with the products of combustion. This explains why the test data for the unit shows such low CO and D/F levels. Such database errors call into question whether EPA has included the correct units in the database used to set the MACT floors in the proposal and whether EPA has undertaken the necessary QA/QC of the database.

Response: The specified data corrections have been processed in the EPA database.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 245

Comment: Attachment A - Identified Data Inaccuracies
1. F-S801 and F-S2801 at Shell Chemical, Geismar, LA, are liquid-fired furnaces per the proposal definition. Their inclusion in the Gas 2 floor is a mistake.
2. Boiler-U202 at Shell Chemical, Geismar, LA fires enough petrochemical process gas to make it a Gas 2 unit, not a Gas 1 unit.
3. B 29 at Georgia Pacific, Green Bay, WI, is Petroleum Coke fired boiler. Its inclusion in the Gas 2 floor is a mistake.
4. B 10 at Georgia Pacific, Green Bay, WI is a Wastewater Sludge fired boiler. Its inclusion in the liquid fired floor is a mistake.
5. EU B 02 at Georgia Pacific, Riincon, GA is a Petroleum Coke fired boiler. Its inclusion in the Gas 2 floor is a mistake.
6. The Hg results for liquid-fired EU 33 Boiler # 3 at Georgia Pacific, Duluth, MN appear invalid. Non-detects were reported as zero, rather than at the detection limits and the tests were run for short times, resulting in particularly high detection limits, thus making the error very significant. Further, the stack results appear to be at odds with the fuel analyses and the stack results are not representative because that stack normally receives emissions from three boilers, but only one was operating, making the Hg removal in the stack ESP higher than normal, among other unusual factors. This data should be discarded.

7. The CO emissions measured in the EPA required test at F-562 at the Western Refining Yorktown, VA was 49.3 ppm @ 3%O2 not 49.3 ppb @ 3% O2 as indicated in the database and floor analysis.
8. Process Heater 1-90 at Westlake Styrene, Westlake, LA is indicated as a Gas 1 process heater, but is believed to have been firing a high hydrogen Gas 2 mixed fuel when the performance test data included in the database was obtained 18 years ago. It is unclear that this 18 year old stack test is valid for the current heater and fuel.
9. Boiler 7103-1-01R at the University of Virginia, Charlottesville, VA, is included in the database as a Gas 1 unit, but is a coal stoker unit. It does fire natural gas as well, but is optimized for coal and meets the proposed definition of a coal unit and does not meet the proposed definition for a Gas 1 unit.
10. The CO value for Boiler G at Equistar Chemical, LaPorte, TX is incorrect in the EPA database. The correct value is 3.39E+01 ppmv @ 3% O2, not 2.11E-02 ppmv @ 3% O2. The value reported was the uncorrected CO concentration and the unit of measure was incorrectly picked as ?g/dscm @ 3% O2 on the survey form. The correct unit of measure selected should have been ppmv @ 3% O2.
11. HS-2041A, B, and C at Hunt Refining, Tuscaloosa, Alabama are included in the database as Gas 1. On average, these units fire 29% Refinery Fuel Gas and 71% PSA Off Gas. While PSA off-gas is often in refinery fuel gas, under the proposal definitions it appears this unit should be reassigned to Gas 2 subcategory.
12. For heater 24-F-1 at the ExxonMobil Refinery, Torrance, CA the stack mercury concentration in lb/MMBTU was miscalculated, because the heat from the Gas Turbine exhaust used as combustion air for this heater was not considered.
13. The dioxin data for the natural gas-fired 150 Furnace at Cytec, Wallingford, CT are misreported as detected levels that are improbably high for natural gas-fired process heaters. The analytical detection limits are reported as mass (pg) rather than as equivalent in-stack concentrations (ng/dscm), and the detection status should have been indicated as DLL indicating some congeners were detected and some are undetected. This results in an average TEQ in the EPA database that is approximately 5000 times higher than the correctly calculated value.
14. The CO emissions from EUCOG-5 #2 gas-fired boiler at Archer, Daniels, Midland, Clinton, Iowa were 0.1 ppm at 3% O2, not 0.1354 ppm@3% O2.
15. The North Variants Boiler at Rubicon LLC, Geismar, LA was firing vent gas (for HCl MACT) and natural gas when tested and should have been assigned to Gas 2, not Gas 1. HCl results are widely scattered and high, raising questions about the quality of the data and the unit operation during the test.
16. Powerhouse Boiler 3 at the Ford Assembly Plant, Wayne, MI fired primarily landfill gas and thus is a Gas 2 unit, not Gas 1.
17. Boiler NO. 4 at Dover light and Power, Dover, OH is shown in the site permit as coal fired, not Gas 1.
18. The Hg results for HB03 at BMW Manufacturing, Greer, SC did not include detection limits for undetected results in summing the separate analytical fractions, resulting in the reported results being a factor of 3 too low. The Hg value for this unit should be recalculated using the detection limit for undetected values.
19. Hg result for HTM Heater 3 at Eastman, Columbia, SC contains several errors and must be corrected. Analytical fraction 3A was omitted from all runs, indicating a possible method deviation voiding comparability to other tests and introduction of a low bias compared to other

tests with all five analytical fractions included (because an undetected result for this sample fraction is not included); sample fraction 5C (analytical fraction 3A) was not collected in Run 1, introducing a low bias compared to other test runs. Mercury detection limits were not included in the sum of separate analytical fraction results for total mercury catch. Average result including detection limits and typical values for missing fractions is 1.7 times higher than reported result.
20. ACET-2A-1 ACET 2A-5 and ACET 2B-1 ACET 2b-5 at Rohm and Haas, Deer Park, TX have been shutdown since 2008 and should not be included in the database.
21. Heater 13-1451 at Valero Refining, Texas City, TX reports that while the source test results were < 0.1 ppm CO @ 3% O2 for all three test runs, CO typically ranges from 0-540 ppm and a monthly average of 11 ppm is typical.
22. Heaters 16 and 17 at Valero Refining, Texas City share a common stack. The site reports that while the source test results were < 0.1 ppm CO @ 3% O2 for all three test runs, CO has varied from 0 to 512 ppm over the last 18 months, with a monthly average of 7.6 ppm (standard deviation 13.2 ppm).
23. Heater 58 at Valero Refining, Texas City, TX reports that while the source test results were < 0.1 ppm CO @ 3% O2 for all three test runs, CO has varied from 0-875 ppm over the past 18 months, with a monthly average of 48 ppm (standard deviation 75.1 ppm).
24. The H2 Plant heater and Heater B-7 at Solutia, Inc., Pensacola, FL fire process gas and natural gas and meet the Gas 2 definition in the proposal, not the Gas 1 definition.
25. The Cold Mill Annealing Oven at Nucor Steel, Crawfordsville, IN should be included in the Gas 1 metal industry subcategory, not the Gas 1 subcategory.
26. EU-39-FH0027 at Coffeyville Refining, Coffeyville, KS is a coal-fired boiler which should be moved from the Gas 1 subcategory.
27. HB-513 at Deltech, Baton Rouge, LA fires natural gas and landfill gas and meets the Gas 2 definition not the Gas 1 definition.
28. Power Boiler 4 at Potlatch, Lewiston, ID fires mostly solids and does not belong in the Gas 1 database.
29. Power Boiler 6 (EU ID 03) at IP, Pensacola, FL fires natural gas and landfill gas and should be in the gas 2 subcategory not Gas 1.
30. The large boiler at Zeeland Farm, Zeeland, MI fires primarily landfill gas and is thus a Gas 2 unit, not Gas 1.
31. Boiler 3 at Severstal, Sparrows Point, MD fires blast furnace gas and belongs in the Gas 2 subcategory, not the Gas 1 subcategory.
32. ES-41 at Cargill, Fayetteville, NC fires natural gas and landfill gas and belongs in the Gas 2 subcategory, not the Gas 1 subcategory.
33. Boilers 2, 9, 10, and 11 at Texas Petrochemicals fire natural gas and petrochemical gas and thus meet the Gas 2 subcategory definition, not the Gas 1 definition.
34. Boiler P-25 at Equistar, Pasadena, TX fires natural gas and petrochemical process gas and meets the Gas 2 subcategory definition, not the Gas 1 definition.

Response: The specified data corrections have been processed in the EPA database.

Commenter Name: Matthew Todd and David Friedman

Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 270

Comment: The Gas 1 dioxin/furan data set consists of 8 units (Figure 11). One is coal-fired and another is co-fired on liquid fuel. All but one of the units has no emission controls. There is one unit with SCR, with emissions at essentially the same level as the uncontrolled units. There is one uncontrolled unit with apparently much higher emissions (#8). Review of the test report shows that these data are over-reported by a factor of approximately 5000 due to mis-reporting of detection limits (analytical mass instead of in-stack concentration).

Response: The specified data corrections have been processed in the EPA database.

Commenter Name: Wayne K. Scharber
Commenter Affiliation: Tennessee Chamber of Commerce and Industry
Document Control Number: EPA-HQ-OAR-2002-0058-2847
Comment Excerpt Number: 1

Comment: EPA has both the legal flexibility and the opportunity to make significant changes to the proposed Industrial Boiler MACT. These changes are needed to correct fundamental technical and data issues that compromise the validity of the proposed standards.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2998.1, Excerpt Number 28.

Commenter Name: Wayne Smith
Commenter Affiliation: Westlake Chemical Corporation
Document Control Number: EPA-HQ-OAR-2002-0058-2785.1
Comment Excerpt Number: 2

Comment: Stack Test Submittal: As a part of the information gathering activity in 2008, Westlake Styrene LP provided a Stack Test Report from a 1992 Test of a Process Heater at the Westlake — Lake Charles Complex. The Stack Test Report was identified as a Natural Gas fueled source. Upon further review of the Stack Test Report it was determined that the fuel for the Process Heater during the 1992 Stack Test was a combination of natural gas and process gas. The process gas stream is primarily Hydrogen. We feel that the use of this Stack Test for the MACT Floor for Natural Gas Boilers and Process Heaters Carbon Monoxide emissions is incorrect and should be corrected. Westlake apologizes for this discrepancy.

Response: The specified data corrections have been processed in the EPA database.

Commenter Name: Dirk J. Krouskop
Commenter Affiliation: MeadWestvaco
Document Control Number: EPA-HQ-OAR-2002-0058-2747.1
Comment Excerpt Number: 3

Comment: Since the release of the data used by EPA to establish the proposed standard, the National Council for Air and Stream Improvement (NCASI) has examined about 100 stack test reports and associated laboratory analysis reports for filterable particulate matter, dioxin/furan, mercury, HCI, formaldehyde, and/or total hydrocarbons (THC). Most of these reports were for boilers assigned to either the biomass or coal subcategories, and most were listed in the EPA database as being among the units with an emission test in the lowest 12% for filterable particulate matter, dioxin/furan, mercury or HCI. NCASI found a disturbing number of problems with the test results appearing in the EPA database for these so-called 'best performing' boilers. It was obvious the test results being used to develop the proposed emission limits had not received an adequate review. Some of the problems identified by NCASI, when corrected, will have a dramatic impact on the proposed emission limits. It is imperative for EPA to thoroughly review all of the available data for the top performing units before promulgating emission limits.

The assessment conducted by NCASI does not by any means encompass a complete review of the database EPA used, but it is alarming that so many errors were found during the short amount of time that was allotted for review during the comment period. For example, of the 11 biomass boilers identified by EPA as best performers for mercury, NCASI identified problems with 7 of those tests that would have resulted in either the source not being identified as a best performer in the first place or would have raised the reported value by at least a factor of two in some cases and an order of magnitude in others.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2998.1, Excerpt Number 28.

Commenter Name: John Hopewell
Commenter Affiliation: American Coatings Association
Document Control Number: EPA-HQ-OAR-2002-0058-2886.1
Comment Excerpt Number: 3

Comment: EPA should address poor data quality concerns.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2998.1, Excerpt Number 28.

Commenter Name: William L. Kovacs
Commenter Affiliation: United States Chamber of Commerce
Document Control Number: EPA-HQ-OAR-2002-0058-2799.1
Comment Excerpt Number: 3

Comment: EPA must conduct a thorough review of the database, correct or eliminate the flawed data, recalculate the MACT floors and associated proposed standards, and provide a new opportunity for public comments (including sufficient time for commenters to conduct their own comprehensive review of the data).

Response: See response for DCN EPA-HQ-OAR-2002-0058-2998.1, Excerpt Number 28.

Commenter Name: Christy Sammon
Commenter Affiliation: Southeast Lumber Manufacturers Association
Document Control Number: EPA-HQ-OAR-2002-0058-2727.1
Comment Excerpt Number: 4

Comment: A far less than complete review of the data set provided for the major source rule reveals apparent errors when compared to the stack test reports for facilities included in the data set. It can only be assumed that an adequate data quality review was not accomplished due to the time constraints imposed by the court mandate to publish these rules. EPA cannot promulgate rules based upon flawed or incorrect data.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2998.1, Excerpt Number 28.

Commenter Name: Mac Gibson
Commenter Affiliation: Alabama Timber Industries, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2717.1
Comment Excerpt Number: 4

Comment: EPA should use all of the available data and gather additional data, if needed, to avoid setting limits for thousands of boilers based on data from only a few. In some cases, the proposed limits are based on only one or two data points, and there are some apparent errors in the data sets. EPA should stop the rulemaking process until data validation and analysis is completed and should re-propose the rules after this validation analysis is complete, even if a court ruling for additional time is needed.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2841.1, Excerpt Number 9.

Commenter Name: Dirk J. Krouskop
Commenter Affiliation: MeadWestvaco
Document Control Number: EPA-HQ-OAR-2002-0058-2747.1
Comment Excerpt Number: 5

Comment: It is incumbent for EPA to perform a thorough review of all stack sampling and associated laboratory analysis reports for the Phase I and II information collection requests, ICR, at least for units currently identified as lop performers' in the various subcategories since errors will affect the currently proposed limits. EPA needs to ensure that all Phase I results are compatible with the Phase II protocols, as well as with the compliance test methods and reporting requirements to be promulgated in the final rule. The Phase II test reports should also be carefully examined and checked to insure the sampling was conducted properly and the emission rates and method detection levels were calculated according to the Phase II protocols.

MWV is very concerned about the achievability of complying with the limits EPA has proposed. EPA is obligated to establish
standards based on performance of the average of the top 12 % units within a specific category.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2998.1, Excerpt Number 28.

Commenter Name: Bill Thomas
Commenter Affiliation: Shuqualak Lumber Company, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2742.1
Comment Excerpt Number: 6

Comment: Based on comments from others, it appears there are also many errors in the data sets that were used. Finally, we are concerned about the quality of all the data used establishing the MACT floors. Has any of the data been verified independently, or by EPA? What if data was flawed/poorly reported/contained errors/was misinterpreted? Should this be the basis of industry-changing regulations?

Response: See response for DCN EPA-HQ-OAR-2002-0058-2998.1, Excerpt Number 28.

Commenter Name: Holly R. Hart
Commenter Affiliation: United Steelworkers Union
Document Control Number: EPA-HQ-OAR-2002-0058-2964.1
Comment Excerpt Number: 6

Comment: Serious concerns have been raised about the quality of data EPA is using to set proposed MACT floors. USW urges EPA to conduct a thorough review of the data it has in hand to correct or eliminate any flawed data, and recalculate the proposed MACT floors on the basis of the correct information. This is in addition to the work gathering and assessing substantial additional data, as USW has recommended above.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2998.1, Excerpt Number 28.

Commenter Name: Jon T. Howard
Commenter Affiliation: Weston Solutions, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2737.1
Comment Excerpt Number: 7

Comment: We are also concerned about the reporting of ICR data using the electronic reporting tool (ERT) and spreadsheet reporting templates (SRT). For example:

We experienced various data entry problems with the use of both the ERT and SRT which we explained to EPA in email and teleconferences. We believe that several of the problems were corrected; however, the ICR data set may include data that were generated using earlier and improperly functioning versions of these tools. Additionally, these tools do not provide audit or check functions so it is possible that some data have not been properly reported or qualified. WESTON encourages EPA to develop a structured audit program that includes comparison of ERT/SRT data with hard copy data reported by the source and develop appropriate corrective action.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2998.1, Excerpt Number 28.

Commenter Name: Quinlan J. Shea
Commenter Affiliation: Edison Electric Institute
Document Control Number: EPA-HQ-OAR-2002-0058-2755.1
Comment Excerpt Number: 8

Comment: Within these severe time constraints, the industry conducted a spot check of 100 stack test reports and associated information from top performers in order to assess the quality of the data the agency relied upon in calculating the MACT floors that underlie the proposed rule.

This spot check revealed numerous data errors – many of which, if corrected, would have a material impact on the stringency of EPA's calculated MACT floors and associated proposed standards. A few illustrative examples include: (1) widespread inconsistency in the data reported under the Phase I and Phase II ICRs, such as entirely different methods of determining and reporting "non detects"; (2) inconsistent reporting of dioxin/furan emissions testing results; (3) inconsistent and incompatible PM emissions testing methods; and (4) mischaracterization of boiler types, such as including a coal-fired boiler in the biomass subcategory. The number and magnitude of the errors provide clear evidence that the database is fundamentally flawed and that any standard derived from the database does not have adequate factual support.

To resolve this problem, EPA must conduct a thorough review of the database, correct or eliminate the flawed data, recalculate the MACT floors and associated proposed standards, and provide a new opportunity for public comments (including sufficient time for commenters to conduct their own comprehensive review of the data).

Response: See response for DCN EPA-HQ-OAR-2002-0058-2998.1, Excerpt Number 28.

Commenter Name: Jon T. Howard
Commenter Affiliation: Weston Solutions, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2737.1
Comment Excerpt Number: 8

Comment: We have examined posted ICR data and found that in some cases, posted data are different from what was entered in the ERT. Additionally, we found that in some cases ERT-generated data were different from data generated by our spreadsheets. Again, WESTON encourages EPA to develop a structured audit program that includes comparison of ERT/SRT data with hard copy data reported by the source and develop appropriate corrective action.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2998.1, Excerpt Number 28.

Commenter Name: Thomas Bakk
Commenter Affiliation: State of Minnesota Senate
Document Control Number: EPA-HQ-OAR-2002-0058-2950
Comment Excerpt Number: 8

Comment: Although it has not been possible to conduct a thorough quality assessment of the entire EPA emission database, AF&PA has done a spot check of one hundred stack test reports. The spot check revealed numerous errors that may have affected the MACT floors and the stringency of the proposed emission limits. It appears that the database is fundamentally flawed, therefore calling into question the factual basis for the standards. The EPA should review the database and correct or eliminate the flawed data and recalculate the emission limits. In addition, because the EPA has not finalized the waste rule definition, the proposal sets out a range of possible final rules, creating a situation where interested parties cannot know which data will ultimately be used to set the emission limits. The definition must be determined before the MACT limits are proposed.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2998.1, Excerpt Number 28.

Commenter Name: Jon T. Howard
Commenter Affiliation: Weston Solutions, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2737.1
Comment Excerpt Number: 9

Comment: The ERT and SRT allowed for the inclusion of interpretive and clarifying comments (which we used, particularly in connection with item 2 above). It is not clear if or how these comments were used by EPA when developing the proposed rules. In the case of data submitted by WESTON, these comments provided important information that would govern the use of reported data. In short, the comments for ERT and SRT submittals were equivalent to the “discussion” component of the “Results and Discussion” section of a standard emission testing report. Accordingly, WESTON encourages EPA to carefully consider all comments accompanying ERT and SRT submittals.

Response: To the extent allowable under this rule schedule, EPA reviewed supporting data provided to explain data. EPA focused its review on the data on low emitting units in order to ensure that data from potential top performers was not erroneous.

Commenter Name: John C. deRuyter
Commenter Affiliation: DuPont
Document Control Number: EPA-HQ-OAR-2002-0058-2793.1
Comment Excerpt Number: 11

Comment: Errors in data used

Review of the top performer unit emissions data and supporting information, including emission test reports indicates many significant problems, including errors in reporting and interpretation, use of emission rates that do not comply with EPA instructions relative to reporting of analyses below detection levels (reporting zero for M29 fractions that are <DL instead of reporting DL), use of emission rate data that is well below the accuracy of the test method and CEMS equipment, and others. The CIBO comments elaborate on examples of specific issues. It is imperative that every set of data used for determining a MACT Floor is carefully reviewed for quality assurance, quality control, and for identification and correction of errors if that can be done. EPA simply must do this to have a defensible outcome.

Response: See response to DCN EPA-HQ-OAR-2002-0058-3213.1, Excerpt Number 68.

Commenter Name: David Bonistall
Commenter Affiliation: NewPage Corp
Document Control Number: EPA-HQ-OAR-2002-0058-2920.1
Comment Excerpt Number: 21

Comment: EPA needs to conduct a thorough data quality assessment on the Boiler MACT database. A spot-check review was conducted on about 100 stack test reports and other information from top performers in order to assess the quality of the data used by EPA to calculate the MACT floors for the proposed rule. This spot-check analysis revealed a number of data errors, which when corrected, will impact the stringency of the proposed standards.

These errors raise significant concerns about the quality of the data in the database being used to establish the Boiler MACT standards. Any standard developed from a database that is fundamentally flawed will not have adequate factual support. EPA can resolve this problem by conducting a thorough review of the database and provide sufficient time and opportunity for public review and comment.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2998.1, Excerpt Number 28.

Commenter Name: Pamela F. Faggert
Commenter Affiliation: Dominion
Document Control Number: EPA-HQ-OAR-2002-0058-2908.1
Comment Excerpt Number: 24

Comment: EPA subcategorized Dominion's Possum Point — Aux Boiler 001 as a "Liquid-fired" unit rather than a "Gas1-fired" unit. This unit only fires natural gas. This error is particularly significant since this unit was included in the
emissions floor analysis for CO for liquid-fired units and identified as the 11th best performing oil-fired unit with regard to CO emissions. This unit does not belong in the liquid fuel subcategory, much less as a "best performing" unit that is used to set the MACT floor for that subcategory. To resolve these problems, EPA should conduct a thorough review of the database, correct or eliminate the flawed data, recalculate the MACT floors and associated proposed standards, and provide a new opportunity for
public comments through a supplemental notice of proposed rulemaking (SNPR).

Response: The specified data corrections have been processed in the EPA database.

Commenter Name: Chris M. Hobson
Commenter Affiliation: Southern Company
Document Control Number: EPA-HQ-OAR-2002-0058-2741.1
Comment Excerpt Number: 42

Comment: Our review of EPA's ICR database suggests that EPA did not adequately review the ICR emissions data prior to conducting the MACT floor analysis. While we understand that an in-depth review of such a massive amount of data would be difficult given the limited timeframe for rulemaking, many of these issues could have been identified by simple outlier screening.

As a starting point for revising the proposed rule, RMB recommends that EPA conduct a more thorough investigation of the ICR data quality. At a minimum, EPA should perform an outlier check of all reported test data, including outliers within each reported test and outliers between tests for units that reported multiple tests. EPA could then exclude such test data or conduct further investigation to confirm whether the data is truly an outlier.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2998.1, Excerpt Number 28.

Commenter Name: Chris M. Hobson
Commenter Affiliation: Southern Company
Document Control Number: EPA-HQ-OAR-2002-0058-2741.1
Comment Excerpt Number: 47

Comment: EPA inappropriately subcategorized VADominionPossumPoint – Aux Boiler 001 as a “Liquid-fired” unit rather than a “Gas1-fired” unit. RMB has confirmed that this unit only fires natural gas. This error is particularly significant since this unit was included in the emissions floor analysis for CO for liquid-fired units.

Response: The specified data corrections have been processed in the EPA database.

Commenter Name: Chris M. Hobson
Commenter Affiliation: Southern Company
Document Control Number: EPA-HQ-OAR-2002-0058-2741.1
Comment Excerpt Number: 51

Comment: EPA identified the ASEA Boiler No. 1 owned and operated by Archer Daniels Midland (ADM) in Des Moines, IA as the best performing coal-fired unit with respect to PM emissions. The reported filterable PM emissions for this unit is 0.0002 lb/106 Btu.16 An examination of the test report also shows average filterable PM2.5 emissions to be 0.0096 lb/106 Btu. For a well-controlled source, PM2.5 is typically at least 50 to 60 percent of total filterable PM emissions. These results suggest that at least one of the two PM averages must be incorrect since the total filterable PM emissions is approximately 50 times less than filterable PM2.5.

Response: The test report for this test was reviewed. It was found that the filterable PM values were from a combined Method 5/29 test. A separate OTM 27/28 train was conducted, and the PM2.5 values were taken from it. The filterable PM values reported with the OTM 27/28 train were much higher than the Method 5/29 train, thus the reason for the much larger PM2.5 values. The validity of both values were confirmed, but they should not be compared to each other because they were not measured concurrently.

Commenter Name: Chris M. Hobson
Commenter Affiliation: Southern Company
Document Control Number: EPA-HQ-OAR-2002-0058-2741.1
Comment Excerpt Number: 53

Comment: 10. Some of the emissions test data were obtained under non-isokinetic test conditions. All isokinetic reference methods specify that isokinetic variation must be limited to ±10%. Test results that are outside of this specification may be rejected at EPA's discretion. A complete list of test runs there were performed during non-isokinetic test conditions can be found in Attachment D of the submittal.

Response: Although the commenter provided a general cutoff for excluding isokinetic variation for some stack tests, other variables must be considered when evaluating the reliability of a test. EPA conducted a detailed review of 17 tests and eliminated some due to improper ISO variation. Further, the facilities performing these tests did not report to EPA that these tests were invalid and given the cursory threshold provide by the commenter without any site-specific testing notes. EPA did not use its discretion to remove this data from consideration.

Commenter Name: Chris M. Hobson
Commenter Affiliation: Southern Company
Document Control Number: EPA-HQ-OAR-2002-0058-2741.1
Comment Excerpt Number: 54

Comment: Some of the reported test runs may be invalid due to failed leak checks. RMB was unable to validate the reported data because the necessary test reports were unavailable. These test runs should be further investigated to determine whether they should be eliminated from the MACT pool. (See submittal Attachment E for a list of test runs with failed leak checks.)

Response: The test reports for the specified data were unavailable, so a review was not conducted. The data was not removed from consideration of MACT floor rankings.

Commenter Name: Chris M. Hobson
Commenter Affiliation: Southern Company
Document Control Number: EPA-HQ-OAR-2002-0058-2741.1
Comment Excerpt Number: 55

Comment: RMB conducted limited outlier screening of the ERT data reported for some of the biomass, coal, and oil-fired units. Potential outliers were determined by assessing the inter-run variability for each test using a logarithmic difference [Footnote: Algorithm compares the absolute difference of the log10 value of each run to the log10 value of the average of the remaining runs against an outlier threshold value of 0.7 (detects variation that is greater than 105 times the difference).] screening algorithm. RMB recommends that these test runs be further investigated to determine whether they should be eliminated from the MACT pool. (See submittal Attachment F for a list of potential outliers.)

Response: The specified data were not further investigated due to time constraints. No further correspondence was received on the specified potential outliers, so none of the specified data was disregarded from MACT floor rankings.

Commenter Name: Domtar Corp
Commenter Affiliation: Guy R. Martin
Document Control Number: EPA-HQ-OAR-2002-0058-2823.1
Comment Excerpt Number: 1

Comment: In 2009, a second ICR mandated extensive stack testing and fuel analyses at roughly 150 boilers and process heaters. EPA selected these units to fill perceived information gaps in the database and to obtain additional test data from numerous 'best performing' units to examine emissions variability. Companies were given only four months to conduct this testing and submit the results to EPA. Four (4) of Domtar mills (Kingsport, TN, Plymouth, NC, Bennettsville, SC and Ashdown, AR) participated in this exercise, at a total cost to Domtar of over $400,000.
The combined database for the 2008 and 2009 data contains a massive amount of information and it is unrealistic to expect that every value in the database has been checked by EPA and its contractor for accuracy. Indeed, several errors in the data submitted by Domtar were found and corrections were sent to EPA before and after the date of publication of the Proposed Rule. However, only a small fraction of the emission
test results in the database has actually been used for developing the proposed numerical standards (Ashdown's results, which included long term variability testing, were excluded) and it is realistic to expect this more limited set of information has been thoroughly reviewed and cross-checked.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2998.1, Excerpt Number 28.

Commenter Name: Tracy Smith
Commenter Affiliation: Coastal Forest Products
Document Control Number: EPA-HQ-OAR-2002-0058-2872.1
Comment Excerpt Number: 1

Comment: A cursory comparison, which is all that time allowed, of the database used to determine emission standards with the individual stack test reports
included in the data set revealed inconsistencies. It can only be assumed that a thorough data quality review was not able to be accomplished due to the time constraints imposed by the court mandate to publish these rules. EPA certainly should not promulgate standards based upon flawed or incorrect data.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2998.1, Excerpt Number 28.

Commenter Name: Dell Majure
Commenter Affiliation: Kimberly Clark Corp.
Document Control Number: EPA-HQ-OAR-2002-0058-2779.1
Comment Excerpt Number: 1

Comment: Given the limited comment period that has been provided on the proposed rule, it simply has not been possible to conduct a thorough data quality assessment on EPA's entire emissions data base. Within these time constraints, the National Council for Air and Stream Improvement conducted a spot check of 100 stack test reports and associated information from top performers in order to assess the quality of the data the Agency relied upon in calculating the MACT floors that underlie the proposed rule.
This spot check revealed numerous data errors – many of which, if corrected, would have a material impact on EPA's calculated MACT floors and associated proposed standards. To name just a few, there was: (1) widespread inconsistency in the data reported under the Phase I and Phase II information collection request (ICR)s, such as entirely different methods of determining and reporting "non detects"; (2) inconsistent reporting of dioxin/furan emissions testing results; (3) inconsistent and incompatible PM emissions testing methods; and (4) mischaracterization of boiler types, such as including a coal-fired boiler in the biomass subcategory. The number and magnitude of the errors provide clear evidence that the database is flawed and that any emission standard derived from the database does not have adequate factual support.

To resolve this problem, EPA must conduct a thorough review of the database, correct or eliminate the flawed data, recalculate the MACT floors and associated proposed standards, and provide a new opportunity for public comments (including sufficient time for commenters to conduct their own comprehensive review of the data).

Response: See response for DCN EPA-HQ-OAR-2002-0058-2998.1, Excerpt Number 28.

Commenter Name: Aubra Anthony, Jr
Commenter Affiliation: Anthony Forest Products Company
Document Control Number: EPA-HQ-OAR-2002-0058-2885.1
Comment Excerpt Number: 2

Comment: One of our biomass boilers at the AFP Urbana, AR mill, SN-12, is shown as one of EPA's top performer for dioxin /furans in the fuel cell/biomass subcategory. However, the database contains multiple errors for this very unit and pollutants. At least two attempts [Email from GBMc & Associates on behalf of AFP to CombustionSurvey@erg.com on 2/22/2010 and to Mr. Brian Shrager on 7/6/2010.] to correct EPA's data collection regarding the facility's units have been made.

Response: The specified data corrections have been processed in the EPA database.

Commenter Name: Timothy J. Porter
Commenter Affiliation: Wheelabrator Technologies Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2812.1
Comment Excerpt Number: 2

Comment: The three (3) WTI "CA Wheelabrator Shasta" biomass fired boilers at our California renewable energy facility were included in the proposed CISIWI MACT rule based on the proposed solid waste definition rule. The inclusion of the CA Wheelabrator Shasta most likely was based on the fact that these units were permitted years ago to combust small amounts of solid waste (such as paper cubes and cardboard) although these fuel types have not been combusted in years. Subsequently these units should be appropriately included in the universe of Boiler MACT units and emissions data subsequently used to derive Boiler MACT limits if they represent the top 12% performing units.

Response: The three Wheelebrator Shasta boilers have been moved to the inventory of major source boilers and process heaters.

Commenter Name: Tom Midyett
Commenter Affiliation: Tennessee Paper Council
Document Control Number: EPA-HQ-OAR-2002-0058-2691.1
Comment Excerpt Number: 3

Comment: Additionally, the TPC has grave concerns about the quality of data used to establish the MACT floors. A limited review by our industry of the data that have been used to set the boiler MACT standards identified errors in units of measure, fuel and boiler categorization, detection limit calculation and measurement techniques. We are very concerned that a rule which impacts not only select sources within our own industry, but also the entire breadth and depth of the nation’s manufacturing sector’s steam and power generating units, establishes emission limits based data that has obvious errors.

We ask EPA to recalculate the proposed limits in a fashion that establishes the MACT floor for each subcategory by identifying the top performers (from the entire population of units in the subcategory) on the basis of the collective, not independent, emissions of the pollutants or pollutant surrogates so that emissions control is achievable and the data on which this is based must be subject to a rigorous quality assurance review.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2998.1, Excerpt Number 28.

Commenter Name: Sheila C. Holman
Commenter Affiliation: North Carolina Department of Environment and Natural Resources
Document Control Number: EPA-HQ-OAR-2002-0058-2798.1
Comment Excerpt Number: 3

Comment: MACT standards are quantitatively based on available emission test data to calculate the MACT floors and set emission limits. The actual numerical values of the standards are sensitive to the particular set of emission data collected and treated for each subcategory and pollutant. Given the sensitivity, it is reasonable to expect that by now EPA would have defined some form of minimum available data quantity/quality requirements in establishing standards to assure their basis is sufficiently rigorous, accurate, and representative. EPA is quite experienced in setting quality assurance {QA) requirements for industry to meet for enforcing emission standards, but so far is hesitant in setting its own QA requirements to meet for developing emission standards.

[Footnote 3: 40 CFR Part 60, Appendices B and F.]

Response: See response for DCN EPA-HQ-OAR-2002-0058-2998.1, Excerpt Number 28.

Commenter Name: David W. Peightal
Commenter Affiliation: Dakota Gasification Company
Document Control Number: EPA-HQ-OAR-2002-0058-3179
Comment Excerpt Number: 3

Comment: In reference to how EPA determined the MACT floors for existing units, issues have risen with respect to data quality and lack of review of test data by EPA.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2998.1, Excerpt Number 28.

Commenter Name: Mark W. Kowlzan
Commenter Affiliation: Packaging Corp. of America
Document Control Number: EPA-HQ-OAR-2002-0058-2913.1
Comment Excerpt Number: 3

Comment: We have grave concerns about the quality of data used to establish the MACT floors. A limited review by our industry of the data used to set the Boiler MACT standards identified errors in units of measure, fuel and boiler categorization, detection limit calculations and measurement techniques. Two of our company's thirteen power boilers that fall under the biomass subcategory in the proposed rule are subject to carbon monoxide (CO), mercury and dioxin/furan emission limits that are based on flawed data. Specifically. for that subcategory the CO limit is based on best performer data from a suspension burner that was misclassified as a stoker; the mercury limit is based on a best performer that did not observe the necessary EPA Method 29 testing procedures; and the dioxin/furan limit is based on a mishandled toxic equivalency quantity calculation that results in an emission rate that is an order of magnitude too low. We find it profoundly disturbing that a rule which impacts not only select sources within our own company but also the entire breadth and depth of the nation's manufacturing sector's steam and power generating units establishes emission limits based on data that has such glaring quality deficiencies.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2998.1, Excerpt Number 28.

Commenter Name: Bill Wemhoff
Commenter Affiliation: National Rural Electric Cooperative Association
Document Control Number: EPA-HQ-OAR-2002-0058-2835.1
Comment Excerpt Number: 4

Comment: EPA's rush to comply with the unrealistic rulemaking schedule it agreed to in the IB MACT rulemaking has resulted in obvious and multiple flaws in the proposed MACT standards. EPA does not appear to have conducted its own quality assurance analysis of the ICR stack testing data. As UARG describes in its comments, even a cursory review of the IB MACT data by its consultant has revealed several important problems with EPA's analysis of the ICR data.

The fact that UARG was able to identify such obvious errors in a very limited review of the IB MACT database raises troubling questions about EPA's apparent blind acceptance of the IB ICR data given time limitations. EPA needs to conduct a thorough quality assurance review of the IB ICR data and only after that review repropose IB MACT limits.

The lesson for the upcoming EGU MACT rulemaking is that EPA must conduct a thorough analysis of the information it receives from its EGU ICR request. If more time is needed for EPA to perform a proper review, it must ask the court to revise the rulemaking schedule.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2998.1, Excerpt Number 28.

Commenter Name: James Johnson
Commenter Affiliation: U.S. Beet Sugar Association
Document Control Number: EPA-HQ-OAR-2002-0058-2827.1
Comment Excerpt Number: 4

Comment: While the beet sugar industry does believe in minimizing its impact to the environment, we do have serious concerns that the proposed rule is overly aggressive. There is evidence that a significant amount of the data and resulting emission limits need to be closely examined, and if needed, the MACT floors adjusted. Failure to do may result in an impossible situation for nearly all boiler operators.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2998.1, Excerpt Number 28.

Commenter Name: Sheila C. Holman
Commenter Affiliation: North Carolina Department of Environment and Natural Resources
Document Control Number: EPA-HQ-OAR-2002-0058-2798.1
Comment Excerpt Number: 4

Comment: The language in the Proposed Boiler MACT preamble is silent on EPA's use of any QA requirements applied to set subcategory emission standards. Interestingly, EPA requested comments on other related data quality issues in setting emission floors, including:
1. Approaches suitable to account for measurement variability in establishing the floor emission limit when based on measurements at or near the method detection level (MDL).
2. Whether there is a more appropriate approach to account for variability in the MACT floor analyses when there are emissions data from a limited number of units in the subcategory.
3. Whether EPA should consider reading the intent of the CAA to allow consideration of 5 sources rather than 12% when there is a source category with greater than 30 sources, but the EPA only has data for less than 30 sources.
Data presented in Tables 2 and 3 of the Proposed Boiler MACT can be used to show the percentage of the population (sources) with data used to set standards ranges from as little as 2% to as high as 63% with an overall average of 27%. The average (27%) and high (63%) population coverage values appear adequate in providing a quantitative rationale to serve as a reliable basis as sufficiently robust, accurate, and representative for standards setting. However, the low {2%) and other single-digit percentage values (for five of nine dioxin emission category standards and for four of the five pollutant standards for the Other Gases Subcategory) do not provide an adequate quantitative rationale for reliable standards setting.

[Footnote 4: Federal. Register pp. 32022 and 32023.]

Response: See response for DCN EPA-HQ-OAR-2002-0058-2998.1, Excerpt Number 28.

Commenter Name: Roy W. Wood
Commenter Affiliation: Eastman Kodak Company
Document Control Number: EPA-HQ-OAR-2002-0058-2917.1
Comment Excerpt Number: 5

Comment: EPA has not adequately quality assured its data, including data accuracy and representativeness of conditions tested.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2998.1, Excerpt Number 28.

Commenter Name: Sheila C. Holman
Commenter Affiliation: North Carolina Department of Environment and Natural Resources
Document Control Number: EPA-HQ-OAR-2002-0058-2798.1
Comment Excerpt Number: 5

Comment: When the NC Attorney General directed DAQ to proceed with the 112(j) process for emission standards and permitting, we began by examining emission data from our sources and the corresponding national database available to EPA at that time. In that examination, we came across some cases where the EPA database did not match our data for the same NC tests in terms of fuel use. For example, EPA mis-categorized a multi-fuel permitted facility emission test data while firing natural gas in the liquid oil data category. We did not retain nor use the EPA data points that were mistaken since our examination of the EPA database was not exhaustive. In other words, the correction of those points would simply mean that those points would be corrected. There was no guarantee the rest of the EPA data would be correct because we only had authority to review our data. As a result, we limited our inquiry to NC data that we reviewed and quality assured (QA'd). Given DAQ had already QA'd data, we consider it EPA's responsibility to likewise QA its handling of our data without our re-review. Given the limited comment period provided on the Boiler MACT proposal, it was not possible to carefully QA the NC emissions data base used by EPA.
EPA must conduct a thorough review of the emission database, fix flawed data, and then recalculate the MACT floors and associated proposed standards.
Rather than wait until parts of the rule are challenged on insufficient available data-related issues, NC DAQ suggests EPA develop and use a set of data QA requirements and standard operating procedures (SOPs) upon which more defensible emission standards can be established.
The data set QA requirements and SOPs should include:
Independent third-party QA review of EPA emission database,
Minimum quantity of sources with data necessary to set a valid floor,
Minimum percent of affected source population with data necessary to set a valid floor,
SOP for treating MDL data in lieu of otherwise valid data, e.g., raising values that are below the MDL to 3-times the MDL.
SOP for handling data at or near the MDL.
SOP for handling CEMS data.
SOP for setting the floor where there are data for less than 30 affected sources, but where the affected source population exceeds 30 sources.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2998.1, Excerpt Number 28.

Commenter Name: Lee B. Zeugin
Commenter Affiliation: Utility Air Regulatory Group
Document Control Number: EPA-HQ-OAR-2002-0058-2880.1
Comment Excerpt Number: 6

Comment: EPA's rush to comply with the unrealistic rulemaking schedule it agreed to in the IB MACT rulemaking has resulted in obvious and multiple flaws in the proposed MACT standards. EPA does not appear to have conducted its own quality assurance analysis of the ICR stack testing data. Even a cursory review of the IB MACT data by RMB Consulting revealed [see submittal for memo.] several important problems with EPA's analysis of the ICR data.

For example, EPA identified the ASEA Boiler No. 1 owned and operated by Archer Daniels Midland as the best performing coal-fired unit with respect to PM emissions. EPA reports filterable PM emissions for this unit of 0.0002 lb/MBTU. An examination of the test report shows that filterable PM using Method 29 is reported as 0.0002 lb/MBTU, but the report also lists filterable PM2.5 emissions of 0.0096 lb/MBTU. These results make no sense because filterable PM2.5 emissions are a subset of total filterable PM emissions. At least one of these two values must be incorrect. The total filterable PM value of 0.0002 lb/MBTU seems more suspect because that level of PM emissions is (1) unprecedented in a coal-fired boiler and (2) at or below the quantification level of a gravimetric method, even for a 4-hour sampling run.

A second example is Dominion Generation’s Possum Point Power Station auxiliary boiler No. 1. EPA identifies that unit as the 11th best performing oil-fired unit with regard to carbon monoxide (“CO”) emissions. However, the test report clearly states that the Dominion unit only fires natural gas. The unit does not belong in the liquid fuel subcategory, much less as a best performing unit that is used to set the MACT floor for that subcategory.

A third example is the unit identified as the best performing oil-fired unit for CO emissions -- the No. 4 Vaporizer at the DAK Americas plant in Moncks Corner, South Carolina. The narrative section of that unit’s test report states that the CO concentration was essentially zero throughout the test runs. EPA used an average CO concentration of 0.0515 ppm [The number of significant figures reported by EPA indicates a level of scientific certainty that finds no support in the test report.] for its analysis of this unit’s test data. RMB Consulting’s examination of the raw, 1-minute CO data revealed that at least half of the values were negative concentrations, suggesting either zero drift and/or calibration issues. RMB Consulting also observed that the CO analyzer was operated on a 0 to 500 ppm range and was calibrated with cylinder gases having concentrations of 231 and 484 ppm. In order to make credible measurements at the extremely low levels reported, the CO analyzer should have been operated on a 0 to 10 ppm range with a nominal calibration gas concentration of 5 ppm. The low-level CO concentrations reported are simply not credible given the way the CO analyzer seems to have been operated.

The fact that RMB Consulting was able to identify such obvious errors in a very limited review of the IB MACT database raises troubling questions about EPA apparent blind acceptance of the ICR test data given time limitations. This rush to use the ICR data without thorough review and analysis is exactly the problem UARG envisioned when it challenged the consent decree schedule EPA agreed to follow in the EGU MACT rulemaking. EPA needs to conduct a thorough QA review of the IB ICR data and only after that review repropose IB MACT limits.

The lesson for the upcoming EGU MACT rulemaking is that EPA must conduct a thorough analysis of the information it receives from its EGU ICR request. If more time is needed for EPA to perform its legally mandated obligations under the CAA, then it must ask the court to revise the rulemaking schedule.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2998.1, Excerpt Number 28.

Commenter Name: Karen S. Price
Commenter Affiliation: West Virginia Manufacturers Association
Document Control Number: EPA-HQ-OAR-2002-0058-2957.1
Comment Excerpt Number: 6

Comment: In light of extensive data sourcing and quality problems, EPA's standards are arbitrary and capricious. The WVMA agrees with NAM that the data EPA gathered to support these rules reflects bias, is incomplete, and is fundamentally flawed.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2998.1, Excerpt Number 28.

Commenter Name: Al Hankins, Jr.
Commenter Affiliation: Hankins Lumber Company, LLC
Document Control Number: EPA-HQ-OAR-2002-0058-2708.1
Comment Excerpt Number: 6

Comment: Based on comments from others, it appears there are also many errors in the data sets that were used. Finally, we are concerned about the quality of all the data used for establishing the MACT floors. Has any of the data been validated independently, or by EPA? What if data was flawed/poorly reported/contained errors/was misinterpreted? Should this be the basis of industry-changing regulations?

Response: See response for DCN EPA-HQ-OAR-2002-0058-2998.1, Excerpt Number 28.

Commenter Name: John T. Heard
Commenter Affiliation: The Virginia Coal Association
Document Control Number: EPA-HQ-OAR-2002-0058-2953.1
Comment Excerpt Number: 6

Comment: Significant changes must be made to both proposed rules to correct fundamental technical and data issues that compromise the validity of the proposed standards. Changes are also needed to address several basic infirmities that call into question the legal viability of key aspects of the rules.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2998.1, Excerpt Number 28.

Commenter Name: Gordon M. Smith
Commenter Affiliation: Mitsubishi Polyester Film, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2912
Comment Excerpt Number: 7

Comment: The most critical shortcoming in EPA's data analysis is merging test results reported by 2008 survey respondents with test results from the 2009 mandatory test program into a single database that was used to identify 'best performers' in each subcategory and calculate emission limits. EPA implicitly assumed they were equivalent in terms of quality without conducting a detailed review of the actual stack sampling and associated laboratory analysis reports.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2998.1, Excerpt Number 28.

Commenter Name: Chris Korleski
Commenter Affiliation: Ohio EPA
Document Control Number: EPA-HQ-OAR-2002-0058-2818.1
Comment Excerpt Number: 7

Comment: Use the best available data to set emission standards that is unbiased and reviewed for quality.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2841.1, Excerpt Number 9.

Commenter Name: Nina E. Butler
Commenter Affiliation: Smurfit-Stone Container Corp.
Document Control Number: EPA-HQ-OAR-2002-0058-2783.1
Comment Excerpt Number: 9

Comment: There are numerous flaws in the emissions database used to establish the proposed Boiler MACT limitations. For example, a thorough review of the data for Smurfit-Stone's Fernandina Beach mill revealed substantial errors, and we have submitted corrections to the mercury, HCl, and PM (filterable) data for this mill to EPA. It is reasonable to assume that the data base contains other significant errors. Smurfit-Stone believes it is incumbent on EPA to ensure that the data used in developing the Boiler MACT standards is accurate and representative of the units in a source category.

Response: No corrections were received for the Smurfit-Stone Fernandina Beach mill.

Commenter Name: Sarah E. Amick
Commenter Affiliation: Rubber Manufacturers Association
Document Control Number: EPA-HQ-OAR-2002-0058-2941.1
Comment Excerpt Number: 9

Comment: Within these severe time constraints, we conducted a spot check in order to assess the quality of the data the Agency relied upon in calculating the MACT floors that underlie the proposed rule.

This spot check revealed numerous data errors – many of which, if corrected, would have a material impact on the stringency of EPA's calculated MACT floors and associated proposed standards. To name just a few, there was: (1) widespread inconsistency in the data reported under the Phase I and Phase II ICRs, such as entirely different methods of determining and reporting "non detects"; (2) inconsistent reporting of dioxin/furan emissions testing results;
(3) inconsistent and incompatible PM emissions testing methods; and (4) mischaracterization of boiler types, such as including a coal-fired boiler in the biomass subcategory. The number and magnitude of the errors provide clear evidence that the database is fundamentally flawed and that any standard derived from the database does not have adequate factual support.

To resolve this problem, RMA recommends that EPA conduct a thorough review of the database, correct or eliminate the flawed data, recalculate the MACT floors and associated proposed standards, and provide a new opportunity for public comments (including sufficient time for commenters to conduct their own comprehensive review of the data).

Response: See response for DCN EPA-HQ-OAR-2002-0058-2998.1, Excerpt Number 28.

Commenter Name: Traylor Champion
Commenter Affiliation: Georgia-Pacific LLC
Document Control Number: EPA-HQ-OAR-2002-0058-2745.1
Comment Excerpt Number: 18

Comment: EPA has placed several GP boilers in the incorrect category.
(i) Unit WIGPGB10 is not a liquid boiler
The WIGPGB10 (GP's Green Bay Broadway Boiler 10) unit listed in Appendix
C-4 of the Memo shows this unit as a liquid-fired boiler. This boiler burns secondary fiber deinking residuals to produce steam for the secondary fiber papermaking process. Secondary fiber deinking residuals are biomass fuel consisting of recovered fiber from the deinking process that cannot be made into paper. Therefore this unit should be included in the biomass category.
(ii) Unit LAGPort Hudson is not a biomass boiler
The LAGPort Hudson - EQT0109 No. 6 CFB unit listed in Appendix C-4 of the Memo shows this unit as being in the MACT floor and a biomass boiler. This boiler burns more than 10% petroleum coke along with biomass and natural gas to make steam for the papermaking process. The probable reason for this boiler
being mischaracterized is that during EPA's Phase I Information Collection Request (ICR) there was no choice in the drop down menus for petroleum coke and the instructions told responders to select coke oven gas instead. Therefore, this boiler should be in the coal category since it burns more than 10% petroleum coke.
(iii) Several other GP units are also mischaracterized as burning coke oven gas The following boilers also have been listed as burning coke oven gas when in fact they burn petroleum coke:

GASRMRincon – EU B002
This boiler is incorrectly listed in the Gas 2 category but should be listed in the coal category because it burns 100% petroleum coke and does not burn coke oven gas (as described above).
GASRMRincon – EU B003
This boiler is correctly listed in the coal category and burns a combination of coal and petroleum coke, but does not burn coke oven gas (as described above)
GASRMRincon – EU B001
This boiler is correctly listed in the coal category and burns a combination of coal and petroleum coke, but does not burn coke oven gas (as described above)
WIGPGreen Bay0218 – B29-Fluidized Bed Boiler #9
This boiler is incorrectly listed in the Gas 2 category but should be listed in the coal category because it burns 100% petroleum coke but does not burn coke oven gas (as described above).
EPA should correct the above errors in its database. This information was communicated to Brian Schrager, U.S. EPA in a letter via email dated 6/24/2010 and included in the submittal Appendix A – Communications with EPA.

Response: The specified data corrections have been processed in the EPA database.

Commenter Name: Traylor Champion
Commenter Affiliation: Georgia-Pacific LLC
Document Control Number: EPA-HQ-OAR-2002-0058-2745.1
Comment Excerpt Number: 19

Comment: EPA has incorrectly listed particulate matter and mercury emissions for GAGPBrunswick – No. 4 Power Boiler.
The GAGPBrunswick – No. 4 Power Boiler unit listed in Appendix C-4 of the Memo shows this unit as being in the MACT floor for filterable particulate emissions of 0.0005 lb/MM Btu (test date 8/5/2009), but this value is actually for the “filterable <2.5 um fraction” from the OTM 27 test. The correct value for filterable PM for this test 0.00602 lb/MM Btu. Also, for mercury listed in Appendix C-5 of the Memo (test date 4/28/2006) EPA shows an incorrect value – the correct value should be 6.05E07. In the same table, EPA shows duplicate values for the August 2009 test results (one should be deleted).
EPA should correct these errors in its database. This information was communicated to Brian Schrager, U.S. EPA in a letter via email dated 6/23/2010 and included in Appendix A – Communications with EPA.

Response: The specified data corrections have been processed in the EPA database.

Commenter Name: Traylor Champion
Commenter Affiliation: Georgia-Pacific LLC
Document Control Number: EPA-HQ-OAR-2002-0058-2745.1
Comment Excerpt Number: 20

Comment: Particulate matter data from GP's Brewton Mill is incorrectly presented in the Memo EPA has incorrectly listed data from unit ALGPBrewton Mill – BR-SPGO-S026 No.3 Power Boiler as 12 individual runs. This boiler has two stacks designated as North and South. On 12/12/2007 and 7/11/2008 the mill performed stack testing for particulate matter on each of the stacks. Therefore, the correct emissions from this boiler are determined by adding the emissions from each stack to get the total emissions from the boiler. The submittal includes Table 13 which shows the correct calculations for the two tests in the "Combined" stack rows. The full test report will be made available to the Agency upon request.

Response: The specified data corrections have been processed in the EPA database.

Commenter Name: Traylor Champion
Commenter Affiliation: Georgia-Pacific LLC
Document Control Number: EPA-HQ-OAR-2002-0058-2745.1
Comment Excerpt Number: 21

Comment: EPA has incorrectly listed particulate matter emissions for GAGPMadisonPly – 800 Wood Waste Boiler.
This unit listed in Appendix C-4 of the Memo shows this unit as being in the MACT floor for filterable particulate emissions of 1.17E-03 lb/MM Btu (test date 8/1/2009), but this value is actually 1.21E-03 after correcting Sample Run #2 for the actual mass of particulate collected. EPA should correct this error in its database. This information was communicated to Brian Schrager, U.S. EPA in a letter via email dated 6/22/2010 and included in Appendix A – Communications with EPA.

Response: The specified data corrections have been processed in the EPA database.

Commenter Name: Richard L. Killion
Commenter Affiliation: Babcock and Wilcox Power Generation Group
Document Control Number: EPA-HQ-OAR-2002-0058-2722.1
Comment Excerpt Number: 22

Comment: There appear to be several discrepancies with the data from the single best performing units that were used to set the emission limits for new units. B&W is concerned about the validity of the data submitted to EPA and the number of other errors that may be present based on our initial review.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2998.1, Excerpt Number 28.

Commenter Name: Traylor Champion
Commenter Affiliation: Georgia-Pacific LLC
Document Control Number: EPA-HQ-OAR-2002-0058-2745.1
Comment Excerpt Number: 22

Comment: EPA has incorrectly listed mercury emissions for VAGPBigIsland – PWR05 – No. 5 Power Boiler.
Although this unit is not listed as being in the MACT floor, Version 5 of EPA's database has an incorrect value for mercury emissions. In the 5/2/2007 test report mercury fractions 3A and 3C were not collected and analyzed nor were the mercury results corrected for blanks.
EPA should delete this test result from its database. This information was communicated to Brian Schrager, U.S. EPA in a letter via email dated 6/22/2010 and included in Appendix A – Communications with EPA

Response: The specified errors have been noted in the EPA database and the data will not be used in future analyses.

Commenter Name: Traylor Champion
Commenter Affiliation: Georgia-Pacific LLC
Document Control Number: EPA-HQ-OAR-2002-0058-2745.1
Comment Excerpt Number: 23

Comment: EPA has incorrectly listed particulate matter and mercury emissions for ORGeorgiaPacificWaunaMill – Fluid Bed Boiler.
This unit, listed in Appendix C-4 of the Memo, is shown in the MACT floor for filterable particulate emissions of 5.80E-04 lb/MM Btu (test date 7/19/2009), but this
value could not be matched with any of the emissions data in the test report. The 7/2009 test report does include the following two correct Method 5-based PM filterable tests: a Method 5/Method 29 test conducted for metals except for mercury ('M5/M29 without Hg') with a value of 2.39E-04 lb/MM Btu, and a Method 5/Method29 test conducted for mercury only ('M5 with Hg') with a value of 4.25E-04 lb/MM Btu.
Although this unit is not listed as being in the MACT floor for mercury, Version 5 of EPA's database has an incorrect value of 7.62E-07 lb/MM Btu for mercury emissions. In the 7/2009 test report mercury fraction 3A was not collected and analyzed nor is it clear that the detection limit reported by the laboratory is consistent
with EPA's Guidance Document 51F. Therefore, EPA should delete this mercury value from its database
EPA should correct these errors filterable PM emission and delete the mercury data from its database. This information was communicated to Brian Schrager,
U.S. EPA in a letter via email dated 6/29/2010 and included in Appendix A – Communications with EPA.

Response: The specified corrections to the filterable particulate data have been made. The specified mercury errors have been noted in the EPA database and will be excluded from future analyses.

Commenter Name: Michael Hutcheson
Commenter Affiliation: Ameren Services
Document Control Number: EPA-HQ-OAR-2002-0058-2803.1
Comment Excerpt Number: 23

Comment: The data in the US EPA's Boiler MACT Emissions Database for Boilers and Process Heaters Containing Stack Test, CEM, & Fuel Analysis Data Reported under ICR No. 2286.01 and ICR No. 2286.03 (version 5) has not been adequately peer reviewed and is too flawed to base calculation of MACT standards

Ameren reviewed the stack test data in the database for the liquid fuel and gas fueled subcategories and found several instances of poorly reported or obviously erroneously reported data used to develop MACT floors. It was also found that the boilers used to establish the MACT floors were not representative of the boiler population as a whole and should not be used to establish MACT standards for the subcategory. The issues with the reported data used to establish the MACT floors are detailed below.

The Conemaugh Plant in New Florence reported a PM sample run (no. 2) which is 1/4 the value of other 2 runs and appears to be an outlier.

The Milan Army Ammunition Plant in Tennessee reported data from a boiler less than 15 MMBtu/hr with no control and this data was used to establish MACT floor for PM and Hg as a best controlled source. The PM data included a non-detect value which indicates a problem with the stack test run. The data for Hg was based on several fuel sample analyses even for a single source at the plant but a Hg stack test of that source was not performed and the source could therefore not be in the best controlled 12 %. The source is uncontrolled burning diesel fuel and the HG floor and variability analysis utilized 29 fuel sample data points at reported at below the same method detection limit. This data skews the variability analysis as it encompasses almost half of the data used to establish variability. The dioxin/furan data from this source was not used to establish the floor but also appears to be flawed as the source reported no detection limits even though the data ranked no. 4 and the 3 sources ranked ahead were all reported as DLL and all but one source after it reported dioxin/furan results as BDL or DLL except 1 (out of 17 boilers).

The GP plant in Green Bay Wisconsin reported PM values for a boiler rated at 95 MMBtu per hour firing wastewater sludges. This source should not be used to establish MACT floor for sources firing fuel oils because based on the definition proposed for solid wastes, no other facility could utilize the sludges from this plant as a fuel without being subject to the incinerator MACT. Additionally, the US EPA selectively chose the lowest test out of three from this source. If the US EPA is going to utilize test data from a source to establish a standard, it must use all stack test data from that source.

The Cherokee Pharm plant in Pennsylvania was used to establish the PM MACT floor based on a 1998 test burning a combination of NG and fuel oil with no indication of the relative percentages of each. US EPA needs to establish that the majority fuel was not NG or at least establish the relative percentages of fuels. Ameren believes that it is improper for the MACT floor for liquid fuels to be based on source test which utilized any amount of NG or other gaseous fuels as they will bias the results and are not reflective of liquid fuel fired boilers. In addition, the source reported both the filterable and total PM as the same value. This is obviously an error and may indicate under reporting of total PM or over reporting of filterable PM.

The Milliken plant in Dewey, South Carolina was used to establish the PM, Hg, HCL and dioxin/furan MACT floors. The data from this plant is based on a boiler burning Anhydrides Waste in a boiler rated at 10.5 MMBtu/hr. No other facility in the nation could utilize this fuel, and as a result, it is improper to utilize the results from this facility as a basis for establishing MACT standards for the entire country. The boiler is uncontrolled and obtains the maximum degree of emission reduction solely by virtue of burning a byproduct fuel which is unavailable to all other facilities. The data from this plant should be put into an “other/byproduct fuels” subcategory which establishes limits for non-petroleum based fuels. In addition, the information in the database indicates the particulate results used to establish the MACT floor were based on method OTM 27 which measures PM10 or PM2.5 emissions even though the data was reported as PM. The results of the particulate fractions testing are being compared against sources who are reporting PM filterable data based on US EPA method 5 and is therefore biased low. This testing methodology is different than that required under the standard, results in biased low data and is also different than all other methods used to establish the PM MACT floor and therefore should be excluded from the analysis.

The GP plant in Duluth, MN was used to establish the Hg floor based on data from a boiler rated at 43 MMBtu/hr and firing #6 fuel oil with no controls. The stack test data indicates that the results are below detectable limits.

The FPL Energy Wyman Plant in Maine is a 72 MMBtu/hr #6 fuel oil fired boiler without controls used to establish the MACT floor for Hg even though the Facility reported relatively high PM emission rates while simultaneously reporting very low Hg. Fuel samples taken during the test resulted in Hg levels on the order of 10-5 #/MMBtu and stack test results were on the order of 10-8 #/MMBtu. This is a loss of 99% of the Hg in the fuel at the stack in a unit with no controls. Detection limit values were not reported and because reported levels are at or below the limit of detection for other tests, it is likely the values are representative of method detection limits and not actual detections of Hg in the stack samples. Because Hg disappears into the ether between the fuel and stack and the suspect manner for which the data for Hg is from stack test is reported, the use of this data is suspect. US EPA should not use data from this Facility for establishing the MACT floor without a thorough quality assurance analysis of the data. Additionally, the US EPA appears to have erred by using the stack test data from this plant and multiple fuel analysis data points from this Facility. In essence, even though the US EPA had fuel variability data from this source, it ignored that data potentially due to the very high Hg values reported. If US EPA is going to maintain that this source is a top performer for Hg, it must use the fuel variability data collected from this source to establish the UPL as it has done with other sources in the top 12 %.

The Cognis plant in Il Boiler 1 is a 67.3 MMBtu/hr boiler burning bioliquids and NG with no controls. Because the biofuels which put this unit in the liquid subcategory are not available at other facilities, it is inappropriate to utilize this facility's boiler emission data for the MACT floor analysis for sources burning commercially available petroleum liquids. Other problems with use of data from this Facility include that the MACT floor includes data from both Boiler 2 and Boiler 1 at the Facility as separately ranked sources even though only one boiler was tested (Boiler 1) and the values for ranking are based on the fuel sample analysis for the boilers. The sample analysis, however, is not representative of the fuel combusted in the boiler as the boilers are dual fuel as they combust a mixture of the bio liquid and NG. The sample data is only representative of the liquid portion of the fuel and is therefore not representative of stack emissions. Because the fuel sample analyses were ND, both values for Boiler 1 and Boiler 2 were the same, resulting in the same ranking for both units. This is improper for establishing the MACT floor. MACT floor data needs to be based on stack test data because it must represent the "maximum degree of emission reduction achievable". Basing the MACT floor on a combination of stack and fuel sample data is not representative of the degree of emission reduction which is achieved from any combustion controls and is therefore biased. Additionally, the animal fats liquid fuel tested has a relatively high higher heat value and is therefore prone to obtaining lower detection limits from fuel sampling on #/heat input basis. This biases the BDL results from this Facility falsely indicating the Hg may be lower relative to other sources then it actually is on a heat input basis.

The Boeing facility in Ridley Park, Pennsylvania tested a 42 MMBtu/hr boiler burning #6 fuel oil with no controls. All results from these tests were non-detect and this boiler ranked as achieving the maximum degree of emission reduction achievable based on the low Hg detection limits during the stack test of this unit.

The Consolidated Edison 59th St. Station in New York, NY is a 180 MMBTu/hr boiler burning No. 6 fuel oil with a fabric filter and sorbent injection controls. This Facility reported Hg emissions as above detection limit values at the level of 0.15 #/tBtu. This is an order of magnitude lower than normal detectable levels of Hg and is therefore suspect.

Ameren believes this source may have incorrectly calculated the method detection limits for the testing performed.

The SD Warren plant in Somerset, Maine was used to establish the Hg floor for Hg. The US EPA indicates in a Table in appendix C-2 to the memorandum on the MACT floor analysis that test data from a Package boiler at the site was used to establish the MACT floor. Based on appendix C-5, the data is from fuel testing of mixed fuels at the site. However this data is not available in the emissions database in the docket and does not correspond to any emissions testing at the facility. In other reporting for the site, the source reported non detect data at 1/2 the method detection limit. This is contrary to the instructions for reporting in the ICR and as a result all data from the facility is suspect and should be thoroughly quality assured. In addition, US EPA should not be using data not reported in the emissions test database for the docket. The data can not be adequately reviewed and commented upon without seeing the unadulterated data prior to US EPA manipulations.

The Electric Boat facility in Connecticut reported Hg data on EMU 17 which is a 7 MMBtu/hr boiler reportedly burning no. 4 fuel oil with no air pollution control equipment. The source is not large enough to even consider for the proposed source category which is boilers > 10 MMBtu/hr, is not, and cannot be representative of the emissions from larger boilers on the order of hundreds of MMBtu/hr. In addition, the source indicates that four (4) hg runs were performed based on test run numbering; however, one run was not included in the database. The Facility also provided data on a single fuel sample (Sample 1) which was attributed to two emission units and that single sample analysis was used twice to establish the MACT floor. The MACT floor should not include data from the Electric Boat facility as it is not representative of source category and the misreported data needs to be deleted from the database. This source was also included in the MACT floor for dioxin/furan testing. Because of its size it should not be used to establish the MACT floor for D/F.

The US Steel Gary Works in Indiana reported Hg emissions from a 500 MMBtu/hr boiler with no controls burning 13 % fuel oil and 87 % blast furnace gas and natural gas. This source is not representative of the liquid fuels subcategory as it is primarily fueled using by-product gases. In addition, the fuel testing of the fuel oil during the test indicates that No. 4 fuel oil was sampled and analyzed, however, test data indicates that No. 6 fuel oil was burned. This discrepancy and the fact that liquid fuels are not the primary fuels should disqualify the data from this source from being used to establish the MACT floor.

Response: The specified corrections have been made to the EPA database.

Commenter Name: Richard L. Killion
Commenter Affiliation: Babcock and Wilcox Power Generation Group
Document Control Number: EPA-HQ-OAR-2002-0058-2722.1
Comment Excerpt Number: 23

Comment: Pulverized Coal CO (Duke Energy Tuscola - IL - Unit #3) – This unit is three units with a common stack. These units have numbers taken in both ppb and ppm making the range of CO readings 0.06 ppm to 78 ppm. The data reported as ppb need to be verified as it is believed that this is incorrect. If the numbers reported as ppb are actually ppm then the data spread is 54 ppm@3%02 to 78 ppm@3%02 and the average increases from 25 ppm@3`)/002 to 62.5 ppm@3°/002.

Response: The specified data corrections have been processed in the EPA database.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 24

Comment: The file size for Version 5 of the database is about 110 MB. It contains 44,389 records with emission test results; 92,822 records with fuel analysis information; and 44,219 records with CEMS data. ACC is concerned that the data has not been thoroughly checked by EPA and its contractor for accuracy.

Over the past several months, ACC and its member companies have examined stack test reports and associated laboratory analysis reports for filterable PM, HG, HCl, dioxin/furan, formaldehyde, and/or total hydrocarbons (THC). There are a disturbing number of problems with the test results appearing in the Version 5 database and it is obvious the test results being used to develop the proposed emission limits have not received an adequate review. ACC has communicated the errors and problems to EPA, and our members have submitted requests for data corrections to EPA, yet in many cases the errors and problems remain unresolved. Some of the problems identified, when corrected, will have a dramatic impact on the proposed emission limits.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2998.1, Excerpt Number 28.

Commenter Name: Traylor Champion
Commenter Affiliation: Georgia-Pacific LLC
Document Control Number: EPA-HQ-OAR-2002-0058-2745.1
Comment Excerpt Number: 24

Comment: EPA has incorrectly listed mercury emissions for VAGPBigIsland – PWR04 – No. 4 Power Boiler
Although this unit is not listed as being in the MACT floor, the Version 5 of EPA’s database has an incorrect value for mercury emissions. In the 5/212007 test report mercury fractions 3A and 3C were not collected and analyzed nor were the mercury results corrected for blanks.
EPA should delete this test result from its database. This information was communicated to Brian Schrager, U.S. EPA in a letter via email dated 7/13/2010 and included in Appendix A – Communications with EPA

Response: The specified data corrections have been processed in the EPA database.

Commenter Name: Richard L. Killion
Commenter Affiliation: Babcock and Wilcox Power Generation Group
Document Control Number: EPA-HQ-OAR-2002-0058-2722.1
Comment Excerpt Number: 24

Comment: Biomass Particulate Matter (GP Cellulose Brunswick - GA - U700 No. 4 Power Boiler) – It appears that the same data was included twice in this data set which significantly lowers the average number. The data set has the exact same data numbers repeated twice on the same dates. This appears to be an error. If one of these sets of data is removed, the average increases from 2.16E-03 Lb/MMBtu to 2.97E-03 Lb/MMBtu.

Response: The specified data corrections have been processed in the EPA database.

Commenter Name: Richard L. Killion
Commenter Affiliation: Babcock and Wilcox Power Generation Group
Document Control Number: EPA-HQ-OAR-2002-0058-2722.1
Comment Excerpt Number: 25

Comment: Biomass HCI (Potlach Forest Warren - AR - Wellons Boiler) – There is a 2-3 order of magnitude difference between the data from 2006 and 2009. There is only a fuel analysis from 2006 on which to compare the fuel chlorine content for comparison.

Response: Corrections to the 2009 data were submitted by the facility in June, 2010. The values in the EPA database are correct as reported by the facility.

Commenter Name: Traylor Champion
Commenter Affiliation: Georgia-Pacific LLC
Document Control Number: EPA-HQ-OAR-2002-0058-2745.1
Comment Excerpt Number: 25

Comment: EPA has incorrectly listed mercury emissions for MNGP Duluth EU 33 Boiler #3 is listed in the database memo (Table C-5) as a best performer for mercury. In the test report performed on 9/10/2009, the reported mercury fractions have been calculated with non-detect fractions being treated as zero instead of at the method detection limit (MDL) as requested in EPA's Guidance Document 51F. GP is aware of conversations between NCASI and EPA in which the Agency requests that the Reporting Detection Level (RDL) should be reported. NCASI has recalculated non-detects at the RDL which results in an emission level of 1.05E-07. EPA should correct this test result in its database. This information was communicated to Brian Schrager, U.S. EPA in a letter via email dated 8/19/2010 and included in Appendix A – Communications with EPA

Response: The specified data corrections have been processed in the EPA database.

Commenter Name: Richard L. Killion
Commenter Affiliation: Babcock and Wilcox Power Generation Group
Document Control Number: EPA-HQ-OAR-2002-0058-2722.1
Comment Excerpt Number: 26

Comment: Biomass Stoker Dioxin/Furan (Green Bay Packaging Morrilton) AR Unit– The reported emissions are two orders of magnitude lower then the next closest unit (1.52E-05 ng/dscm at7%02 to 1.62 E-03 ng/dscm at7%02). This brings into question the validity of this data set.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2998.1, Excerpt Number 28.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 27

Comment: On the basis of these errors, which we believe are likely replicated in each subcategory, many of the units now identified as "top performers" may not have that status after a thorough review of the database. It is incumbent on EPA to ensure the quality of the data on which the proposed rule is based. ACC would be happy to provide EPA additional information on specific problems identified in our review of the database.

The EPA database that forms the basis for setting the proposed MACT standards for boilers contains emission test results for PM using EPA Method 5, CO using EPA Method 10, chlorinated dioxins and furans using EPA Method 23, HCl using EPA Method 26/26A, and Hg using EPA Method 29, Ontario Hydro (ASTM D6784-02), and Method 101A.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2998.1, Excerpt Number 28.

Commenter Name: Richard L. Killion
Commenter Affiliation: Babcock and Wilcox Power Generation Group
Document Control Number: EPA-HQ-OAR-2002-0058-2722.1
Comment Excerpt Number: 27

Comment: Biomass Stoker CO (Temple Inland Thomson - GA - BW B001) – Why did EPA choose this unit as the best performer when there are multiple units in the EPA data with lower average CO (82 out of 120). Also, the spread of the data calls into question the accuracy of the tests (spread 1.4 ppm at 3%02 to 2780 ppm at 3%02).

Response: See response for DCN EPA-HQ-OAR-2002-0058-1877.1, Excerpt Number 2.

Commenter Name: Kevin M. Dempsey
Commenter Affiliation: American Iron and Steel Institute
Document Control Number: EPA-HQ-OAR-2002-0058-2998.1

Comment Excerpt Number: 28

Comment: Given the limited comment period that has been provided on the Proposed Rule, it simply has not been possible to conduct a thorough data quality assessment on EPA's entire emissions data base. EPA's failure to provide adequate time for an appropriate assessment of the data violates the agency's obligation to provide a full and fair opportunity for public comment on the proposed rule. Within these severe time constraints, industry representatives conducted a spot check of 100 stack test reports and associated information from top performers in order to assess the quality of the data the agency relied upon in calculating the MACT floors that underlie the proposed rule.

This spot check revealed numerous data errors – many of which, if corrected, would have a material impact on the stringency of EPA's calculated MACT floors and associated proposed standards. To name just a few, there was: (1) widespread inconsistency in the data reported under the Phase I and Phase II ICRs, such as entirely different methods of determining and reporting "non detects"; (2) inconsistent reporting of dioxin/furan emissions testing results; (3) inconsistent and incompatible PM emissions testing methods; and (4) mischaracterization of boiler types, such as including a coal-fired boiler in the biomass subcategory. The number and magnitude of the errors provide clear evidence that the database is fundamentally flawed and that any standard derived from the database does not have adequate factual support.

To resolve this problem, EPA must conduct a thorough review of the database, correct or eliminate the flawed data, recalculate the MACT floors and associated proposed standards, and provide a new opportunity for public comments (including sufficient time for commenters to conduct their own comprehensive review of the data).

Response: EPA has made substantial revisions to the database since the proposal. These revisions have been based on specific corrections to data and additional data submissions received since the proposal. These substantial changes are discussed in the January 2011 memorandum from Graham Gibson, ERG, to EPA entitled "Handling and Processing of Corrections and New Data in the EPA ICR Databases".

Commenter Name: Richard L. Killion
Commenter Affiliation: Babcock and Wilcox Power Generation Group
Document Control Number: EPA-HQ-OAR-2002-0058-2722.1
Comment Excerpt Number: 28

Comment: Biomass Dutch Oven Dioxin/Furan (Flakeboard Eugene - OR - Boiler #2) There is no listing of the individual dioxin/furan compounds in the database, just the totals. How did EPA evaluate the TEQ without the individual compounds?

Response: The specified data corrections have been processed in the EPA database.

Commenter Name: Alicia Oman
Commenter Affiliation: National Association of Manufacturers
Document Control Number: EPA-HQ-OAR-2002-0058-2845.1
Comment Excerpt Number: 28

Comment: As our members and other organizations review the data underlying EPA's proposed rule, we continue to identify notable errors that renders the data utterly unreliable and thus in violation of Clean Air Act standards. This include errors in fuel and boiler categorizations, errors in calculation of detection limits, errors in measurement techniques that render test results invalid, and others. Fundamentally, failure to correct such data errors will result in arbitrary and capricious rulemaking.

Errors have been found in data from sources that EPA has identified as "top performers." Errors in "top performer" data is particularly problematic, because that data are the foundation for EPA's calculation of MACT floors that will apply to all sources in the same subcategory emitting that pollutant. Specific examples of such data errors are specifically detailed in comments by others, but include: a top performer in the Gas 2 subcategory actually burns petroleum coke and not coke oven gas; the CO limit for biomass stoker boilers was based on top performer data from a suspension burner that was misclassified as a stoker; the dioxins/furans limit for biomass stoker boilers and coal fluidized boilers was based on data that had been reported on a Toxic Equivalency Quantity (TEQ) basis and was mistakenly corrected to its TEQ value a second time, resulting in values an order of magnitude lower; the Hg limit for biomass boilers was based on data that did not follow the required Method 29 procedures, where the source has recently asked EPA to remove data from the database.

To resolve this problem, EPA must conduct a thorough review of the database, correct or eliminate the flawed data, recalculate the MACT floors and associated proposed standards, and provide a new opportunity for public comments (including sufficient time for commenters to conduct their own comprehensive review of the data). Finalizing the proposed standards with these underlying errors would render the standards immediately indefensible. See e.g., Columbia Falls Aluminum Co. v. EPA, 139 F.3d 914, 923 (D.C. Cir. 1998) ("An agency's use of a model is arbitrary if that model "bears no rational relationship to the reality it purports to represent.").

Response: See response for DCN EPA-HQ-OAR-2002-0058-2998.1, Excerpt Number 28.

Commenter Name: Richard L. Killion
Commenter Affiliation: Babcock and Wilcox Power Generation Group
Document Control Number: EPA-HQ-OAR-2002-0058-2722.1
Comment Excerpt Number: 29

Comment: Liquid Fuel Mercury (GP Duluth - MN - EU33 Boiler #3) – The unit is listed as having a common stack for the one liquid fuel unit and two biomass fired units. The mercury testing says it was at the stack. If that is the case, this is not valid data unless the other two boilers were shut down or isolated in some way or the testing was done somewhere before the mix-point.

Response: An independent review of the data by the National Council for Air & Stream Improvement (NCASI) resulted in submittal of corrected mercury data points for this boiler. Those corrected data points have been processed in the EPA database.

Commenter Name: Richard L. Killion
Commenter Affiliation: Babcock and Wilcox Power Generation Group
Document Control Number: EPA-HQ-OAR-2002-0058-2722.1
Comment Excerpt Number: 30

Comment: Other Gas Firing CO (Shell Chemical Geismar - LA - Furnace F-S801) –There are three data points not included in the average because the 10% fuel is listed as Gas-1. This may be an error. The percentage of Gas-1 in those points is 23.9, while it is 32.8 in the test points included. Why would the points with the lower NG firing not be included? Inclusion of these points would increase the average from 0.0129 ppm at 3%02 to 0.055 ppm at 3 percent O2.

Response: The specified data corrections have been processed in the EPA database.

Commenter Name: Brad James
Commenter Affiliation: Trinity Consultants
Document Control Number: EPA-HQ-OAR-2002-0058-2853.1
Comment Excerpt Number: 30

Comment: Errors in EPA's data set and its calculations are evident throughout the spreadsheets it has provided. These errors draw into question the accuracy and appropriateness of the MACT floors proposed by this rulemaking. When setting a standard that will cost industry millions of dollars to comply, precision is critical. Even a few transcription errors can result in significant changes to the proposed emission limits. EPA's failures in this regard have resulted in a proposal that is inappropriate, erroneous and unattainable.

Due to these and other likely problems in the data and math that form the foundation of this rule, EPA should reexamine its data, ensure its accuracy, and employ a more representative metric for ranking the sources and identifying the top performers.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2998.1, Excerpt Number 28.

Commenter Name: Brad James
Commenter Affiliation: Trinity Consultants

Document Control Number: EPA-HQ-OAR-2002-0058-2853.1
Comment Excerpt Number: 31

Comment: Other commenters have already highlighted certain clear issues with the data set, and U.S. Sugar incorporates those comments by reference here. See, e.g., Consolidated Edison's August 3, 2010, comment that Table 2 of Appendix C-2 identifies 80 individual boilers at one facility with identical chlorine emission values, an outcome which is nearly statistically impossible. The numerous "#DIV/0!" errors appearing throughout the spreadsheet is also suggestive of a careless approach to the calculation process. Additionally, U.S. Sugar can point out several other specific problems in the data and calculus.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2998.1, Excerpt Number 28.

Commenter Name: Douglas J. Van Pelt
Commenter Affiliation: ExxonMobil
Document Control Number: EPA-HQ-OAR-2002-0058-2968.1
Comment Excerpt Number: 31

Comment: C. A review by American Petroleum Institute (API) on the data being used to set the MACT limits reveals numerous errors, including errors in fuel and boiler categorizations, errors in calculation of detection limits, and errors in measurement techniques that render test results invalid.

Errors have been found in data from sources that EPA has identified as "top performers." The top performer data was the foundation for EPA's calculation of MACT floors. Examples of such data errors include: a top performer in the Gas 2 subcategory actually burns petroleum coke and not coke oven gas; the

dioxins/furans limit for biomass stoker boilers and coal fluidized boilers was based on data that had been reported on a Toxic Equivalency Quantity (TEQ) basis and was mistakenly corrected to its TEQ value a second time, resulting in values an order of magnitude lower; and the Hg limit for biomass boilers was based on data that did not follow the required Method 29 procedures.

It is imperative that errors in the floor setting database be corrected before any final emission limits are promulgated.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2998.1, Excerpt Number 28.

Commenter Name: Brad James
Commenter Affiliation: Trinity Consultants
Document Control Number: EPA-HQ-OAR-2002-0058-2853.1
Comment Excerpt Number: 32

Comment: The problems are further exacerbated in those categories for which only one source is setting the MACT Floor. For example, in the dutch oven biomass category, only one source is utilized to determine the threshold for dioxin/furans. That source is emitting 0.16 ppm, while the only other two sources are emitting 9 and 17 ppm respectively. Such a disparity raises questions of accuracy, or, alternatively, suggests an outlier that should be disregarded from a statistical perspective. At a minimum, one boiler should not be the only standard for a rule that applies across all industries nationwide.

Response: EPA based the floor calculations on the top 12 percent of data available in each subcategory. There was ample time provided to submit additional data and EPA updated its calculations with new data received during the proposal. As noted by commenters, dioxin/furan formation and concentrations can vary. There were no other reasons provided to suggest elimination of this test and so this data was not removed as an outlier.

Commenter Name: Christopher S. Colman
Commenter Affiliation: Hovensa LLC
Document Control Number: EPA-HQ-OAR-2002-0058-2863.1
Comment Excerpt Number: 41

Comment: We note, however, that even with additional time to review information in the docket, HOVENSA has not been able to decipher data in the docket with the certainty needed to adequately comment on the proposal. In many cases, the information in the database
* Is not clear on what fuel or fuels are being combusted and in what proportions
* Does not contain long term or even short term data for heaters or boilers fired at rates above 10% residual fuel oil.
* Does not provide basic design or duty information for the heater or boiler
* Does not provide information about the facility that the heater or boiler supports
* Is often one time stack test data
* Is unclear as to what the data fields in the database mean

We would like to thank EPA for allowing an additional 45 days to submit comments on the proposed Boiler MACT rule. However, even with the additional time, HOVENSA did not have sufficient time to gather additional data in support of these comments. HOVENSA is continuing a data gathering efforts and intends to supplement these comments.

Response: See response for DCN EPA-HQ-OAR-2002-0058-1778, Excerpt Number 75.

Commenter Name: Lee B. Zeugin
Commenter Affiliation: Utility Air Regulatory Group
Document Control Number: EPA-HQ-OAR-2002-0058-2880.1
Comment Excerpt Number: 93

Comment: In one or more public forums, EPA staff acknowledged that it performed little, if any, quality assurance on the stack testing database. Even a cursory examination of EPA's IB MACT database verifies the absence of quality assurance. For example, EPA identified the ASEA Boiler No. 1 owned and operated by Archer Daniels Midland (ADM) in Des Moines, IA as the best performing coal-fired unit with respect to PM emissions. For this unit, EPA lists filterable PM emissions to be 0.0002 lb/106 Btu.[42 U.S.C. §7412(d)(1).,Table 3] However, when we examine the ADM test report, we not only find the 0.0002 lb/106 Btu value for PM from the Method 29 filter analysis, but we also observe that ADM reported average filterable PM2,5 emissions to be 0.0096 lb/106 Btu. Of course, filterable PM2,5 is a subset of total filterable PM emissions. For a well-controlled source like this ADM boiler, PM2,5 might be 50 to 60 percent total filterable PM emissions. However, there is no conceivable way to reconcile total filterable PM emissions being X50 times less than filterable PM2.5 — at least one of the two PM averages must be incorrect. Certainly, the 0.0002 value should be considered suspect because that measurement would (1) reflect an unprecedented PM concentration and (2) be at or below the quantification level of the gravimetric method, even for 4-hour sampling runs.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2741.1, Excerpt Number 51.

Commenter Name: Lee B. Zeugin
Commenter Affiliation: Utility Air Regulatory Group
Document Control Number: EPA-HQ-OAR-2002-0058-2880.1
Comment Excerpt Number: 94

Comment: We felt the need to examine some of the underlying data that EPA used to support a CO emission limit of 1 ppm by volume for oil-fired units. A CO emission limit of 1 ppm certainly grabs your attention, especially when you realize that the national ambient air quality limit (NAAQS) for
CO is 9 ppm for an 8-hour average.[See 40 C.F.R., §50.8(a)(1).] We cannot identify or think any other instance in EPA's 40-year history where the Agency has proposed to set an emission limit that is considerably lower than a NAAQS, which in and of itself is protective of public health and welfare. [We recognize that in this rule EPA is proposing a CO limit as a surrogate for various organic HAPs and not to protect public health. Regardless, the comparison provides context for just how draconian some of the proposed emission limits are.]

EPA identified the No. 4 Vaporizer owned and operated by DAK Americas in Moncks Corner, SC as the best performing oil-fired unit with respect to CO emissions. According to the narrative in the test report, the CO concentration was essentially zero throughout the test runs. [Page 7-1, "Section 114 Boiler MACT Data Collection Test Program at No. 4 Vaporizer," report prepared by TRC Environmental Corp., Raleigh, NC, TRC Project No. 169023.] For its analysis, EPA used an average CO concentration equal to 0.0515 ppm (note the significant figures). We examined the raw (1-minute) CO data and observed that at least half of the values were negative concentrations, suggesting either zero drift and/or calibration issues. We also observed the CO analyzer was operated on a 0 to 500 ppm range and was calibrated with a cylinder gases having concentrations of 231 and 484 ppm, respectively. If one wanted to make credible measurements

in the range claimed by the test contractor, the CO analyzer should have been operated on a 0 to 10 ppm range with a nominal calibration gas concentration of 5 ppm. Given the way the CO analyzer appeared to have been operated, such low-level CO concentrations are simply not credible.
EPA identified Auxiliary Boiler No. 1 owned and operated by Dominion Generation's Possum Point Power Station as the 11th best performing oil-fired unit with respect to CO emissions. [Page 5, "NOx and CO Emissions Test Report for the Auxiliary Boiler Stack at the Possum Point Power Station," prepared by the Air Compliance Group, Roanoke, VA, Contract No. V8548.] The problem is, as the report clearly states, the Dominion unit only fires natural gas. The Dominion unit does not belong in the liquid fuel subcategory, much less the pool of MACT floor units.

Response: See response for DCN EPA-HQ-OAR-2002-0058-1877.1, Excerpt Number 2.

Commenter Name: Wayne Brandt
Commenter Affiliation: Minnesota Forest Industries
Document Control Number: EPA-HQ-OAR-2002-0058-3220
Comment Excerpt Number: 8

Comment: Fundamental Flaws in the Emissions Database.
Although it has not been possible to conduct a thorough quality assessment of the entire EPA emission database, AF&PA has done a spot check of one hundred stack test reports. The spot check revealed numerous errors that may have affected the MACT floors and the stringency of the proposed emission limits. It appears that the database is fundamentally flawed, therefore calling into question the factual basis for the standards. The EPA should review the database and correct or eliminate the flawed data and recalculate the emission limits.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2998.1, Excerpt Number 28.

Data Standardization Techniques

Commenter Name: David A. Buff
Commenter Affiliation: Golder Associates Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2801.1
Comment Excerpt Number: 22

Comment: F-Factors for wood have been used to develop emission limits for boilers burning bagasse. In its MACT floor calculations for CO, EPA used the F-Factor for wood to develop emission rates in parts per million by dry volume (ppmvd), based on FSI's submitted stack test data. The FSI completed an F-Factor study for the Florida Department of Environmental Protection many years ago. This study demonstrated that F-Factors for wood are not applicable to bagasse fired boilers, and also demonstrated that no single F-factor was representative of bagasse firing. This again is due to the nature (variability) of bagasse fuel and bagasse boiler operation. The FSI has since then submitted actual CO data in ppmvd @ 3 percent oxygen (O2) for all stack tests, so it is not necessary to use an F-factor for conversion.

Response: EPA has replaced the initially reported data which was standardized using an F-Factor with the newly formatted data from the Florida Sugar Industry. As a result, there is minimal CO data from bagasse combustion in the EPA database which is standardized using an F-Factor.

Commenter Name: Chris M. Hobson
Commenter Affiliation: Southern Company
Document Control Number: EPA-HQ-OAR-2002-0058-2741.1
Comment Excerpt Number: 49

Comment: 7. EPA required that sources use Method 19 to calculate pollutant concentration on a 'lb/mmbtu' basis. However, it appears that some of the sources performed the data conversion using actual heat input based on fuel consumption data. Also, many of the sources used the default F-factor values specified in Method 19. For sources that co-fire multiple fuel types, this could be problematic unless the sources conducted fuel analysis to accurately quantify the F-factor. Furthermore, for sources that reported emissions results as a concentration, EPA applied an average F-factor based on the Method 19 default values if multiple fuels were fired. In some cases, it appears that the F-factor was prorated according to the reported heat input of the various fuels while for others it appears as a straight average. The bias in the reported 'lb/mmbtu' number for not prorating the default values could be significant. For example, for units co-firing coal and natural gas it could be as high as +/- 5%. [Footnote: Assuming a blend ratio of 10% coal/90% gas, the bias would be +5%. Assuming a blend ratio of 90% coal/10% gas, the bias would be -5%.]

Response: EPA used the data provided by sources to the survey and incorporated site-specific corrections as they were received. There was not enough background data to review F-Factor calculations incorporated into all of the results provided to EPA.

Commenter Name: Chris M. Hobson
Commenter Affiliation: Southern Company
Document Control Number: EPA-HQ-OAR-2002-0058-2741.1
Comment Excerpt Number: 50

Comment: In the ICR database, EPA corrected the reported values of CO and D/F TEQ to a standardized O2 concentration (either 3% O2 or 7% O2 depending on the pollutant) only if the O2 basis was provided in the raw data. However, for data that were reported without a specified O2 concentration EPA assumed the reported value to be 0% O2. This does not appear to be an issue for the Phase II data since EPA specified the required format of the data to be in units of "lb/mmbtu" or specified O2 corrected concentrations depending on the pollutant. However, this could be an issue for some of the Phase I data. A review of the biomass & coal data for HCl, HF, PM, and Hg shows that there are a number of units that did not include a reported O2 correction factor in the raw data. This could be a significant negative bias (20-30%) depending on the actual stack O2 concentration.

Response: The EPA database was investigated where a zero percent oxygen level was assumed for Hg, HCl, filterable PM, and CO. Individual tests with low standardized values were re-standardized based on the reported oxygen percentage, where available. The resultant numbers showed very little significant change between the standardized values using an assumed zero percent oxygen level and the standardized values using actual oxygen percentages. There is a significantly small subset of data with oxygen levels at and above 20 percent, with the majority of oxygen concentrations falling under 15 percent.

Commenter Name: Chris M. Hobson
Commenter Affiliation: Southern Company
Document Control Number: EPA-HQ-OAR-2002-0058-2741.1
Comment Excerpt Number: 52

Comment: The MACT floor data contains at least several data sets where the emissions were reported with incorrect units of measure due to unit conversion problems. For instance, in the MACT floor data for CO for PC-fired units, all of the measurements for Duke Energy Tuscola (Units 1, 3, and 4) where the CO concentration in the ICR database is less than 1 PPM are incorrect due to unit conversion problems. A review of the ICR emissions test spreadsheet file shows that the source did not report the units of measure for certain tests. EPA had assumed that the correct unit of measure for these test runs was "PPB" rather than "PPM". EPA then converted these values to PPM in the database and used them in the emissions floor analysis. This resulted in reported data for these test runs that were three orders of magnitude lower than actual measurements. This error is especially critical because this unit was used to set the standard for CO for new PC-fired units. It also affects most of the data used to set the standard for CO for existing PC-fired units.

Response: The specified data corrections have been processed in the EPA database.

Rule Language Corrections

Rule Language: Definitions (existing)

Commenter Name: Carter Strickland, Jr
Commenter Affiliation: New York City Department of Environmental Protection
Document Control Number: EPA-HQ-OAR-2002-0058-1600.1
Comment Excerpt Number: 2

Comment: Clarify definition of gas curtailment. Under applicable gas utility tariffs, DEP is required to switch to oil when certain conditions are met, generally when temperatures drop below a set trigger point. The rules' definitions should encompass all such conditions.

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-3174, Excerpt Number 2 to view the response.

Commenter Name: Myra C. Reece
Commenter Affiliation: South Carolina Department of Health and Environmental Control
Document Control Number: EPA-HQ-OAR-2002-0058-2525.1
Comment Excerpt Number: 3

Comment: The proposed definition of "deviation" in 40 CFR 63.7575 does not establish guidelines to determine continuous compliance with limits and work practice standards in the proposed rule. The definition states a deviation is not always a violation. While we agree with this assertion, the EPA should clearly define when deviations become violations as the EPA has defined in previous rules such as 40 CFR 63 Subpart MM — National Emission Standards For Hazardous Air Pollutants For Chemical Recovery Combustion Sources At Kraft, Soda, Sulfite, And Stand-Alone Semichemical Pulp Mills, 40 CFR 63 Subpart LL — National Emission Standards For Hazardous Air Pollutants For Primary Aluminum Reduction Plants, and 40 CFR 63 Subpart DD — National Emission Standards For Hazardous Air Pollutants From Off-Site Waste And Recovery Operations.

Exceedance Of An Emission Limit Should Be Considered A Violation When Using A Continuous Emission Monitor (CEM)

An affected source required to use a continuous emission monitor (CEM) that fails to comply with an emission limit should be considered a violation even during startup and shutdown events. Continuous emission monitoring data obtained from best performing units, and used in establishing the standards, include periods of startup and shutdown. The EPA did not establish separate emission standards for these periods because startup and shutdown are part of routine operations and are being addressed by the proposed standards. There should not be discretion for what constitutes a violation when an affected source required to have a CEM fails to meet the specified emission limit.

Establish A Violation Threshold For Baghouse Detection Leak System Deviations

The EPA proposes an operating limit for units controlled by a fabric filter in 63.7530(b)(3)(iv). This limit applies to units which choose to demonstrate continuous compliance by using a bag leak detection system to be operated such that the bag leak detection system alarm does not sound more than 5 percent of the operating time during a 6-month period. In 63.7540(b), the EPA proposes that facilities report each instance as a deviation from the emission limit for each instance the facility did not meet an emission limit and operating limit. Because the EPA has stated that the use of the above-mentioned alarm system demonstrates continuous compliance, then any additional deviations above the allowed 5 percent of the operating time during a 6-month period should be considered violations.

Establish Violation Thresholds For Continuous Opacity Monitoring Systems (COMS) And Continuous Parameter Monitoring Systems (CPMS) Deviations

The EPA has established violation thresholds for operating limits for other section 112(d) source categories such as those found in 63.864(k)(2), 63.848(i), and 63.695(e)(5). This rule needs to clearly identify when boilers or process heaters are in violation of the standards when operating parameters used to demonstrate continuous compliance are not met. Also, the EPA proposes the use of continuous opacity monitoring systems (COMS) and continuous parameter monitoring systems (CPMS) for certain affected boilers and process heaters to demonstrate continuous compliance with the proposed standards. The rule needs to include a percentage of time during a 6-month period that these continuous monitoring systems (CMS) are required to be operational and meet any operating limit in order to determine compliance.

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-2740.1, Excerpt Number 14 to view the response.

Commenter Name: Stephen R. Gossett
Commenter Affiliation: Eastman Chemical Company
Document Control Number: EPA-HQ-OAR-2002-0058-3137.1
Comment Excerpt Number: 4

Comment: We are confused by the use of the term "common stack". While we have some boilers that emit via a common stack, they have their own emissions control equipment and ductwork prior to the common stack that allows stack gas sampling prior to the stack.

Response: Please refer to the preamble for treatment of data from common stacks. Affected units with a common stack may each have separate air pollution control systems located before the common stack, or may have a single air pollution control system located after the exhausts come together in a single flue.

Commenter Name: Steven M. Maruszewski

Commenter Affiliation: The Pennsylvania State University
Document Control Number: EPA-HQ-OAR-2002-0058-2729.1
Comment Excerpt Number: 5

Comment: Definitions- Boiler and Hot Water Heater
The definition for hot water heaters does not adequately distinguish between residential-type units and industrial/commercial/institutional units. It is clear in the Preamble that the intent is to include institutional boilers. To clarify, it is suggested additional language to the hot water heater definition be added to include “for domestic hot water use”. Penn State does have hot water heaters that are above the 120 gallon threshold but do not exceed 160 psig or 210 °F. It is unclear if these devices are exempt or if they are considered boilers using the broad boiler definition. If they are considered boilers, then the tune-up requirements would apply and adds to the large number of units subject to the work practice standards of biennial tune-ups.

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-2998.1, Excerpt Number 46 to view the response.

Commenter Name: Michael Palazzolo
Commenter Affiliation: Alcoa Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2967.1
Comment Excerpt Number: 5

Comment: The proposed rule defines Metal process furnaces to include "natural gas-fired annealing furnaces, preheat furnaces, reheat furnaces, aging furnaces, and heat treat furnaces. The aluminum industry also treats metal in furnaces termed "homogenizing furnaces". While these furnaces would accurately and appropriately be considered a type of "heat treat" furnace, we request that EPA add "homogenizing furnaces" to those listed in the definition to avoid future questions of rule interpretation by OECA, EPA Regional and State agency personnel.

Response: EPA has revised the definition of metal process furnaces in the final rule to include homogenizing furnaces.

Commenter Name: Robin Mills Ridgway
Commenter Affiliation: Purdue University
Document Control Number: EPA-HQ-OAR-2002-0058-2782.1
Comment Excerpt Number: 6

Comment: Definition of Unit Designed to Burn Oil overly restrictive

Purdue University’s Boiler #3 is a natural gas fired unit that can also burn oil. Because Purdue’s utility plant is the only source for campus heating steam, the availability of fuel for emergencies is paramount. For Purdue’s Boiler #3, fuel oil is only used when a natural gas curtailment order is in effect, or for training and testing. Boiler #3’s annual use of fuel oil over the last 10 year period is as follows: average use 2,130 mmBtu/yr, 1-year peak use 7,124 mmBtu/yr. The unit cost of firing fuel oil is $17.16/mmBtu with natural gas at $6.26/mmBtu at the current market price for oil. At 2.7 times higher than natural gas, there is no economic driver to use oil over natural gas. However, the ability to fire oil if necessary is retained to ensure delivery of steam to campus even if natural gas were not available.

The proposed rule definition of “Unit designed to burn oil subcategory” (§63.7575 page 32065) reads:

Unit designed to burn oil subcategory includes any boiler or process heater that burns any liquid fuel, but less than 10 percent solid fuel on a heat input basis on an annual average, either alone or in combination with gaseous fuels. Gaseous fuel boilers and process heaters that burn liquid fuel during periods of gas curtailment, gas supply emergencies or for periodic testing of liquid fuel not to exceed a combined total of 48 hours during any calendar year are not included in this definition.

This definition would categorize Purdue’s Boiler #3 as a liquid fired boiler even though it runs only several days per year on oil and only out of necessity. The substantial cost of compliance with performance requirements for the oil fired subcategory is incredibly burdensome for a unit that fires natural gas nearly all of the time. This unit also meets the definition of “Unit designed to burn gas 1(NG/RG)”. Purdue requests that EPA consider modifying the definition of Unit designed to burn oil to include only units that burn more than 10 percent on a heat input basis of oil and eliminate the qualifier “any” from the “Unit designed to burn oil” definition.

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-2729.1, Excerpt Number 6 to view the response.

Commenter Name: Steven M. Maruszewski
Commenter Affiliation: The Pennsylvania State University
Document Control Number: EPA-HQ-OAR-2002-0058-2729.1
Comment Excerpt Number: 6

Comment: Definitions - Units designed to burn oil category
The 48 hour limit within the definition for units designed to burn oil subcategory contradicts the definition for units to burn gas 1 definition. A unit is designated as a gas unit if it burns 90% natural gas on a heat input basis. Oil would be the backup during periods of gas curtailment or gas supply emergencies. It can be interpreted that once the 48 hours is reached, the unit becomes an oil unit and then the limits for an oil unit would apply. 48 hours is a short and arbitrary time period and is a much stricter parameter than the 90% heat input limit. Periods of gas curtailment or supply

emergencies are outside the control of the facility and should not count against the facility regardless of the length of time it occurs.
One of the options available to the University to meet Boiler MACT is to switch to firing only natural gas. For reasons of reliability and safety, an on-site source of backup fuel will be required. The logical choice is fuel oil. As currently stated, the University's boilers will become "liquid fuel fired units" after firing fuel oil for just 48 hours per year. Training and testing alone would require at least two days per calendar year leaving no time allowed for emergencies and curtailments, the reason for having fuel oil back up. A resolution similar to the recently published RICE MACT would better address the needs of the University. That rule incorporates an understanding that emergency conditions are in addition to hours used for testing, training and other non-emergency matters. Or, the Administrator could adopt the definition of "gas-fired boiler" as given in the Area Source Boiler MACT.

Response: EPA has revised the definition in the final rule to exclude gas curtailment periods and gas supply emergency periods from the 48-hour limit on liquid fuel combustion at gas units. EPA has also added that curtailments and emergencies could be of any duration.

Commenter Name: G. Vinson Hellwig and Robert H. Colby
Commenter Affiliation: National Assocation of Clean Air Agencies
Document Control Number: EPA-HQ-OAR-2002-0058-2841.1
Comment Excerpt Number: 35

Comment: The definition of "coal" in the section 112 major source rule includes "coal refuse." Coal refuse is defined as coal wastes that have ash content higher than 50 percent and heat value of less than 6000 BTU. The rule then sets out that it applies to units that combust "coal." However, units that combust coal refuse with those properties may well be subject to section 129 limits. EPA should correct the definition to avoid any confusion on this issue.

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-2765.1, Excerpt Number 35 to view the response.

Commenter Name: Stephen R. Gossett
Commenter Affiliation: Eastman Chemical Company
Document Control Number: EPA-HQ-OAR-2002-0058-3137.1
Comment Excerpt Number: 37

Comment: The definition of natural gas needs to be revised to match recent definition changes to include gases (such as treated landfill gas and synthetic natural gas) that are not from geologic formations.

EPAs' proposed definition of natural gas reads (in part) as follows:

Natural gas means (1) a naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane.

On January 28, 2009, EPA finalized natural gas definition changes in NSPS Subparts Da, Db, and Dc as follows:

Natural gas means:
(1) A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane; or
(2) Liquid petroleum gas, as defined by the American Society of Testing and Materials in ASTM D1835 (incorporated by reference, see § 60.17); or
(3) A mixture of hydrocarbons that maintains a gaseous state at ISO conditions. Additionally, natural gas must either be composed of at least 70 percent 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).

The addition of item 3 in the definition allows other gases that are essentially the same as natural gas, such as synthetic natural gas or treated landfill gas, to be included in the definition. It is unnecessary to restrict the definition to only gases from geologic formations. The net impact of this third definition is to promote the beneficial combustion of clean gaseous fuels, such as clean Landfill Gas, which might otherwise be released into the atmosphere or flared. As EPA has indicated in its Landfill Methane Outreach Program (LMOP),

The U.S. Environmental Protection Agency's Landfill Methane Outreach Program (LMOP) is a voluntary assistance program that helps to reduce methane emissions from landfills by encouraging the recovery and beneficial use of landfill gas (LFG) as an energy resource. LFG contains methane, a potent greenhouse gas that can be captured and used to fuel power plants, manufacturing facilities, vehicles, homes, and more.

http://www.epa.gov/lmop/

EPA should define "Natural Gas" to be identical to the definition in § 60.41Subpart Da. EPA could add a de minimus level of fuel dependent inorganic HAPs to this definition to ensure these HAPs are not present in gases qualifying as natural gas.

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-2775.1, Excerpt Number 55 to view the response.

Commenter Name: Britt S. Fleming
Commenter Affiliation: Auto Group
Document Control Number: EPA-HQ-OAR-2002-0058-2775.1

Comment Excerpt Number: 55

Comment: EPA defines "natural gas" in proposed § 63.7575, as:

(1) A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane; or
(2) Liquid petroleum gas, as defined by the American Society for Testing and Materials in ASTM D1835-03a, "Standard Specification for Liquid Petroleum Gases" (incorporated by reference, see § 63.14(b). [Footnote: 75 Fed. Reg. at 32,065.]

The first part of the definition seems to rely on EPA's definition of "natural gas" in several previous MACT standards promulgated by EPA. [Footnote: See Subpart HH, NESHAP from Oil and Natural Gas Production Facilities, 40 C.F.R. § 63.761; Subpart HHH, NESHAP from Natural Gas Transmission and Storage Facilities, 40 C.F.R. § 63.1271.] Both of these rules address processors and providers of natural gas, not customers or end users of the gas. Given that end users do not know or have control of the source of materials introduced into the distribution system, EPA's proposed definition of "natural gas" is problematic if any kind of biogas, landfill gas, or "synthetic gas converted from coal" is in the main pipe. EPA's proposed definition needs to be expanded to cover other types of fuel gases that are carried through the main pipeline.

To address this concern, the Auto Group recommends that EPA add a third component to the definition that would include "any gas that is transported through a commercial natural gas pipeline." This addition would allow fuel gases that are carried through the commercial pipeline to be treated as natural gas and regulated as such. Furthermore, it would not require consumers to determine what type of fuel gas is in the natural gas pipeline and whether that fuel gas comes from a geologic formation or from some other source that results in commercial grade natural gas.

Response: EPA has modified the definition of natural gas in the final rule to be consistent with the definition in 40 CFR part 60 subparts Db and Dc. These changes should address the concerns that sometimes natural gas utilities blend other fuels such as landfill gas or biogas into the pipeline and allow for sources other than geological formations that may enter the pipeline. It has also incorporated a definition of propane as part of natural gas. It has not included the commenters suggestion to include any gas that comes through a natural gas pipeline.

Commenter Name: Britt S. Fleming
Commenter Affiliation: Auto Group
Document Control Number: EPA-HQ-OAR-2002-0058-2775.1
Comment Excerpt Number: 57

Comment: EPA also must clarify the definition in proposed § 63.7575 for "unit designed to burn oil subcategory." [Footnote: See 75 Fed. Reg. at 32,065.] As drafted, the definition states that gaseous fuel boilers and process heaters are not included in the oil-fired unit subcategory as long as the combined total hours of operation during gas curtailment, gas supply emergencies, or periodic testing of liquid fuel does not exceed 48 hours. [Footnote: See 75 Fed. Reg. at 32,065.] The Auto Group objects to the inclusion of periods of gas curtailment or supply emergencies given that end users have no control over the frequency or duration of these periods. Additionally, the proposed 48 hour limit does not provide adequate time to startup the oil burner, make adjustments and perform stack testing as may be required by state operating permits. This definition should be revised to eliminate the specified 48 hour limit.

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-2729.1, Excerpt Number 6 to view the response.

Commenter Name: Britt S. Fleming
Commenter Affiliation: Auto Group
Document Control Number: EPA-HQ-OAR-2002-0058-2775.1
Comment Excerpt Number: 58

Comment: The proposed definition in § 63.7575 for "waste heat process heater" also presents a concern that must be addressed by EPA in the final rule. According to the proposed definition, a "waste heat process heater" does not include those waste process heaters incorporating duct or supplemental burners designed to supply 50% or more of the total rated heat input capacity of the waste heat process heater. [Footnote: See 75 Fed. Reg. at 32,066.] The threshold for supplemental burners should be based on utilization instead of supplemental burner capacity. For example, supplemental burners are fired at high capacity during startup, but then "throttle back" to minimum level during normal operation. If the burner capacity is limited to less than 50%, then there would be startup problems for some sources.

Response: EPA has deleted the middle sentence of the definition, which included the 50 percent criteria, from the final rule.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 109

Comment: The proposed definition of natural gas in §63.7575 includes only the prior NSPS definition, not the 2009 NSPS Subparts Db and Dc revisions. The natural gas definition for this rule needs to be consistent with that rule and should, therefore, also include the following: "(3) A mixture of hydrocarbons that maintains a gaseous state at ISO conditions. Additionally, natural gas must either be composed of at least 70 percent 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)." The addition of item 3 in the definition allows other gases that are essentially the same as natural gas, such as synthetic natural gas or treated landfill gas, to be included in the definition. It is unnecessary to restrict the definition to only gases from geologic formations. The net impact of this third part of the definition is to promote the beneficial combustion of clean gaseous fuels, such as clean Landfill Gas, which might otherwise be released into the atmosphere or flared.

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-2775.1, Excerpt Number 55 to view the response.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 110

Comment: EPA has been very consistent throughout the proposal to use 10% as a threshold for movement from one subcategory to another. For example the most stringent – coal – includes units that burn at least 10% coal. The next – biomass – includes units that burn at least 10% biomass and less than 10% coal. The first sentence of the oil (liquid) subcategory includes any liquid fuel, but less than 10 % solid fuel. Therefore, it logically follows that a plain reading of the Gas 1 subcategory would be that EPA intended to include any unit that burns at least 90% gas and less than 10% of any other fuel. However, the second sentence in the oil (liquid) subcategory emphasized above is in contradiction with the Gas 1 definition by implying that any more than 48 hours (2 days) per year of liquid fuel firing would reclassify the unit into the liquid category. EPA should not limit liquid firing during periods of curtailment, and liquid firing during curtailment should not count toward any 10 percent liquid firing allowance, as these periods are out of the control of the boiler operator.

AF&PA proposes the following definition for the Gas 1 subcategory:

“The Gas 1 (NG/RG) subcategory includes any boiler or process heater that burns at least 90 percent natural gas, propane, refinery gas, or off-gas streams for petrochemical and chemical plant processes on a heat input basis on an annual average and less than 10 percent of any solid or liquid fuel.”

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-2729.1, Excerpt Number 6 to view the response.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 111

Comment: AF&PA proposes the following definition for the liquid boiler subcategory:
"The liquid subcategory includes any boiler or process heater that burns at least 10 percent liquid fuel, but less than 10 percent solid fuel on a heat input basis on an annual average, either alone or in combination with gaseous fuels. Gaseous fuel boilers and process heaters that burn liquid fuel during periods of gas curtailment, gas supply emergencies or for periodic testing of liquid fuel are not included in this definition."

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-2863.1, Excerpt Number 54 to view the response.

Commenter Name: James Santory
Commenter Affiliation: Calgon Carbon Corp.
Document Control Number: EPA-HQ-OAR-2002-0058-2956.1
Comment Excerpt Number: 1

Comment: For purposes of regulatory clarity and consistency with other definitions in the proposed rule, the definition of "waste heat boiler" should be revised so that the delineation of heat input to a unit is based on an annual average. Several definitions in the proposed rule are based on the annual average heat input to a unit including "unit designed to bum gas 1 (NG/RG) subcategory" and "unit designed to bum coal." Accordingly, for consistency and clarity, we suggest the following changes to the definition of "waste heat boiler":

Waste heat boiler means a device that recovers normally unused energy and converts it to usable heat. Waste heat recovery boilers incorporating duct or supplemental burners that supply 50 percent or more of the total rated heat input eapaeity of the waste heat boiler, on an annual average, are not considered waste heat boilers, but are considered boilers. Waste heat boilers are also referred to as heat recovery steam generators.

Response: EPA has deleted the middle sentence of the definition, which included the 50 percent criteria, from the final rule.

Commenter Name: Walter Tyler
Commenter Affiliation: Invista
Document Control Number: EPA-HQ-OAR-2002-0058-2761.1
Comment Excerpt Number: 2

Comment: When comparing the above definition for the "oil" unit subcategory with the definition of the "Gas 1" subcategory, there is the potential for a conflict based on the 48-hour limitation in the "oil" subcategory definition. INVISTA, therefore, suggests that EPA clarify the oil subcategory definition by eliminating the phrase in the second sentence limiting a Gas 1 unit to 48 hours of oil burning. The revised "oil" subcategory text would be modified as follows:

Recommended Text in 63.7575, Definitions:
Unit designed to burn oil subcategory includes any boiler or process heater that burns any liquid fuel, but less than 10 percent solid fuel on a heat input basis on an annual capacity factor average, either alone or in combination with gaseous fuels. Gaseous fuel boilers and process heaters that burn liquid fuel during periods of gas curtailment, gas supply emergencies or for periodic testing of liquid fuel not to exceed a combined total of 48 hours during any calendar year at less than a 90 percent annual capacity factor are not included in this definition.

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-2729.1, Excerpt Number 6 to view the response.

Commenter Name: James Santory
Commenter Affiliation: Calgon Carbon Corp.
Document Control Number: EPA-HQ-OAR-2002-0058-2956.1
Comment Excerpt Number: 2

Comment: The EPA should clarify that the reference to duct or supplemental burners in the proposed definition of "waste heat boiler" means burners that introduce fuel directly into the combustion unit where the heat recovery is also located. Burners that introduce fuel in an upstream combustion unit (e.g., incinerator, thermal oxidizer, or afterburner) are part of the upstream combustion unit that is not a "boiler" because it has no heat recovery. Subsequent recovery of the waste heat in a downstream unit does not render the combustion unit a "boiler."

Response: EPA has updated the definition of waste-heat boiler within the final rule. Please refer to the response to comment EPA-HQ-OAR-2002-0058-2956.1, excerpt 1 or the final rule for updates to this definition.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 2

Comment: This proposal applies to boilers and process heaters at major sources. Boiler is defined in proposed 63.7575 as an enclosed device using controlled flame combustion and having the primary purpose of recovering thermal energy in the form of steam or hot water. A device combusting solid waste, as defined in 40 CFR 241.3, is not a boiler. Waste heat boilers are excluded from this definition. However, the commercial/institutional boiler and industrial boiler definitions in 63.7575 include units that generate electricity, as well as those that generate steam or hot water. While there may not be any boilers that generate electricity without first

generating steam or hot water, there may be such devices in the future or these definitions might be misinterpreted to include devices that generate electricity without combustion, e.g., nuclear reactors, piezoelectric generators, wind turbines. Including electricity generation in the commercial/institutional boiler and industrial boiler definitions serves no purpose and should be removed, so that these definitions mirror the general boiler definition.
Recommendation: Remove electricity generation from the definitions of commercial/institutional boiler and industrial boiler in 63.7575.

Response: EPA has removed "electricity generation" from the definitions in the final rule as per commenter's request. This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-2960.1, Excerpt Number 3 to view the response.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 3

Comment: We are unclear what the term controlled flame combustion means and ask that the Agency explain its significance.

Recommendation: Clarify the meaning of “controlled flame combustion” as used in the boiler definition.

Response: EPA has revised the definition in the final rule. Controlled flame combustion refers to a steady-state, or near steady-state, process wherein fuel and/or oxidizer feed rates are controlled.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 4

Comment: Waste heat boilers are appropriately excluded from the definition of boiler. However, waste heat boiler is defined in 63.7575 not to include waste heat boilers that have supplemental firing, where ?50% of the heat duty of the waste heat boiler comes from supplemental firing. It is unreasonable to consider such supplementary fired waste heat systems as boilers for the purposes of this rule, because their characteristics were not considered in the rulemaking record, they are not represented in the database, the rule compliance procedures are inappropriate for such equipment, the controls considered for normal boilers and process heaters are not applicable and the interactions with other NESHAP rules have not been addressed.

The data record for this proposal did not address these situations or demonstrate what MACT would be for supplementary fired boilers. Because the configuration of a supplementary fired system is totally different than that of a traditional boiler, results from a traditional boiler cannot be extended to supplementary fired boilers. Nor would we expect similar combustion characteristics, since the flame occurs in a different atmosphere and under different temperature, pressure and composition conditions than those in a traditional boiler. For instance, the O2 content of the flame zone for a supplementary fired burner is dependent on the O2 content of the exhaust gas from the primary combustion device and is typically well below the O2 content of air. This characteristic alone, significantly impacts the stack organic HAP, CO and NOx emissions.

A good example of the problem is a waste heat system in a sulfur recovery unit incinerator stack. Because the gases in an SRU incinerator have low heating value, it is very easy for the 50% criteria in the proposal to be exceeded. Clearly, there is nothing in the EPA database that approximates this situation and none of the analyses addressed this type of mixed stack gas. It is not even clear whether the types of controls EPA has considered would work in this unusual environment.

Combustion emissions from supplementary fired waste heat systems are exhausted from the stack of the combustion device (often a gas turbine) from which the waste heat is being recovered. Thus, the emissions from the two devices are combined. The stack monitoring and testing procedures specified in the proposal would not work, because the emissions from the supplementary fired system cannot be distinguished from the emissions of the other combustion source.

Furthermore, add-on controls for supplementary fired equipment would be much different than for normal boilers or process heaters, because they would be handling gas from two combustion sources, the exhaust system is constructed differently, the exhaust gas has different properties and, particularly for gas turbines, the backpressure exerted by add-on controls increases fuel use and emissions from the primary combustion device as well as the waste heat system and could interfere with the add-on NOx controls that are already in place for many such systems. For all of these reasons, the controls evaluated in this rulemaking are not appropriate for or reflective of the controls that would be used for supplementary waste heat systems.

Finally, the primary combustion source is usually already subject to a set of requirements (e.g., NSPS GG and KKKK and/or NESHAP rules such as Part 63 Subpart YYYY and/or SIP requirements) and the Agency has not considered how this proposal would interact with those existing requirements.

Overall, we do not believe the Agency has shown that any supplementary fired boilers have been considered in any portion of this rulemaking or that this NESHAP proposal was developed with such units considered. Thus, there is no technical or legal basis for applying the proposed standards to supplementary fired boilers of any firing percentage.

Recommendation: Revise the definition of waste heat boiler to eliminate the 50% criteria. We recommend the following:

Waste Heat Boiler means a device that recovers normally unused energy and converts it to usable heat. Waste heat recovery boilers incorporating duct or supplemental burners are considered waste heat boilers

If the 50% criterion is not removed, the Agency must clarify it. Under the proposed definition of waste heat boiler in 63.7575 duct or supplemental burners that are designed to supply 50 percent or more of the total rated heat input capacity of the waste heat boiler are not considered waste heat boilers. However, heat input is defined in the same section as "Heat input means heat derived from combustion of fuel in a boiler or process heater 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, kilns, etc." Based on the heat input definition all supplemental firing is 100%, because you can only count the fuel fired in establishing the total rated heat input capacity of the waste heat system.

Recommendation: If the 50% criterion is maintained, establish the 50% as the annual firing of the supplemental burner(s) divided by the total rated waste heat recovery.

Response: EPA has updated the definition of waste-heat boiler within the final rule. Please refer to the response to comment EPA-HQ-OAR-2002-0058-2956.1, excerpt 1 or the final rule for updates to this definition.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 7

Comment: Natural gas is defined in the proposal as follows.

Natural gas means:
(1) A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane; or
(2) Liquid petroleum gas, as defined by the American Society for Testing and Materials in ASTM D183503a, ?'standard Specification for Liquid Petroleum Gases" (incorporated by reference, see 63.14(b)).

The latest definition of natural gas in the NSPS Subpart Db and Dc rules also include a paragraph 3 as follows in order to include synthetic natural gas generated from coal3. [Footnote: Added to the NSPS subparts by amendment on January 28, 2009 (74 FR 5072).]

a mixture of hydrocarbons that maintains a gaseous state at ISO conditions. Additionally, natural gas must either be composed of at least 70 percent 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)

This paragraph should be added to the proposed definition, so this rule is consistent with the other combustion rules potentially applicable to these units.

Recommendation: Add paragraph 3 from the NSPS Subparts Db and Dc natural gas definitions to the natural gas definition in this rule.

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-2775.1, Excerpt Number 55 to view the response.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 13

Comment: Process heater is defined in 63.7575 as “an enclosed device using controlled flame, that is not a boiler, and the unit’s primary purpose is to transfer heat indirectly to a process material (liquid, gas, or solid) or to a heat transfer material for use in a process unit, instead of generating steam. Process heaters are devices in which the combustion gases do not directly come into contact with process materials....”
We are unclear what the phrase that is not a boiler means and suggest it be deleted. Per the boiler definition, a boiler has the primary purpose of producing steam or hot water, while, according to the process heater definition, a process heater has the primary purpose of providing heat to a process material or a heat transfer material. Since a unit cannot have two primary purposes, a process heater cannot be a boiler as the quoted phrase would seem to suggest. Thus, we recommend the phase be deleted from the process heater definition. We note that it is not uncommon for some process heaters to generate significant quantities of steam from waste heat. Thus, the suggestion that a unit can only be a process heater if it is not a boiler (i.e., a steam generator) significantly confuses the determination of device type.
Recommendation: Remove the term “that is not a boiler” from the process heater definition.

Response: EPA acknowledges the comment and removed "that is not a boiler" from the definition of process heater in the final rule.

Commenter Name: Robert D. Morrison
Commenter Affiliation: Abbott Laboratories
Document Control Number: EPA-HQ-OAR-2002-0058-2764.1
Comment Excerpt Number: 14

Comment: The definition of units designed to burn Gas 1 and units designed to burn Gas 2 must be clarified (40 CFR 63.7575, 75 FR 32017). The definitions of units to define Gas 1 and Gas 2 in 40 CFR 63.7575 are ambiguous in the proposed rule. A Gas 1 unit burns at least 90 percent Gas 1 (without specifying any restriction on the remaining 10 percent). A Gas 2 unit burns "gaseous fuels other than ... (Gas 1) ... not combined with any other solid or liquid fuels." The firing of Gas 2 versus Gas 1 is not specified. The definitions do not affirmatively resolve the status of a unit that burns, for example, 91 percent Gas 1 and 9 percent Gas 2. It would seem logical that such a unit would be considered Gas 1, and discussion in the Boiler MACT preamble seem to support that interpretation (75 FR 32017). However, this interpretation should be clarified in the definitions that will be included in the regulation as an alternative assumption could have a dramatic effect on unit requirements.

Response: In response to a similar comment, this issue has been resolved by amending the definition of Gas 2 unit to eliminate the ambiguity.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 14

Comment: Additionally, we are unclear what the term controlled flame combustion means and ask that the Agency explain its significance.

Recommendation: Clarify the meaning of "controlled flame" as used in the process heater definition.

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-2960.1, Excerpt Number 3 to view the response.

Commenter Name: Chris Greissing
Commenter Affiliation: Industrial Minerals Association
Document Control Number: EPA-HQ-OAR-2002-0058-2740.2
Comment Excerpt Number: 14

Comment: It also is unreasonable for EPA to classify as a deviation "any period for which the monitoring system is out of control and data are not available for required calculations." Proposed 63.7525(a)(6). There will be times, even with a well-maintained and functioning CEMS, where the system will be out of operation. No technology is infallible. Many state permits recognize this reality and require data availability for a minimum percentage of operating hours in month or quarter with the minimum percentage depending on the CEMS technology. EPA should amend Proposed 63.7525(a)(6) to allow for some reasonable amounts of missing data.

Response: EPA acknowledges the comment but the definition of deviation in 63.7525(a)(6) has remained as proposed.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 21

Comment: The last sentence of the temporary boiler definition specifies that Any temporary boiler that replaces a temporary boiler at a location and is intended to perform the same or similar function will be included in calculating the consecutive time period. This language creates a problem because there is no time period associated with the replacement. It is not unusual for a temporary boiler to be used for less than 180 days during turnarounds that occur several years apart. Under the proposal these boilers would not be considered temporary, because each boiler replaces the previous one and performs the same function, even though there is a significant gap between the occurrences. We believe that replacements that occur after a gap of at least one year should not be considered consecutive for the purposes of this definition.

Recommendation: Revise the last sentence of the proposed temporary boiler definition, as follows:

Any temporary boiler that replaces a temporary boiler at a location and is intended to perform the same or similar function will be included in calculating the consecutive time period, if the replacement occurs within 12 months of the removal of the previous temporary boiler.

Response: EPA acknowledges the comment and revised the definition to match the definition of "portable" in the GHG reporting rule, as suggested by another commenter.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1

Comment Excerpt Number: 27

Comment: The proposed Gas 2 subcategory definition would capture units that also meet the Gas 1 definition, because they burn <10% Gas 2. Similarly, the Gas 2 definition would not allow a unit that fires primarily Gas 2 to fire up to 10% liquids, as the Gas 1 and liquid subcategory definitions allow and as the preamble states is the intent [Footnote: On page 32012 it states If your new or existing boiler or process heater burns gaseous fuel and less than 10 percent, on an annual average heat input basis, of liquid or solid fuel, we are proposing that the unit is in one of the gas subcategories]. In these situations, it appears a particular unit could be in more than one subcategory at the same time. We, therefore, recommend that the gas subcategory definitions be revised as follows, including the revisions recommended in comment II.C.a.1 if two gas subcategories are maintained in the final rule.
Unit designed to that burns gas 1 (NG/RG) subcategory includes any boiler or process heater that burneds at least 90 percent natural gas and/or refinery gas on a heat input basis on an annual averagein the previous calendar year.

Unit designed to that burns gas 2 (other) subcategory includes any boiler or process heater that burneds greater than 10 percent gaseous fuels other than natural gas and/or refinery gas and less than 10% not combined with any solid or liquid fuels on a heat input basis in the previous calendar year.

Recommendation: Make the Gas 1 and Gas 2 subcategory definitions consistent as recommended above.

Response: EPA has revised the definitions of units designed to burn gas 1 and units designed to burn gas 2 to avoid overlap of the subcategories in the final rule. See final rule for revised definitions.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 28

Comment: Proposed section 63.7575 contains two different definitions for the subcategory covering liquid fuels.

The proposed definition of “liquid fuel subcategory” should be removed and any use of the term “liquid fuel subcategory” anywhere in the regulatory language should be replaced.

The term “unit designed to burn liquid fuel,” should be used exclusively and consistently throughout the rule and in the Tables. “Liquid” is a clearer and more comprehensive term than “oil” and we therefore believe that term should be used throughout the rule. Using consistent terminology throughout the regulation is critical to assuring understanding of the requirements.

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-2863.1, Excerpt Number 54 to view the response.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 29

Comment: Under the proposed definitions, units that burn gas and <10% liquid on an annual basis would appear to be in both a "gas subcategory" and the "unit designed to burn oil subcategory." This needs to be corrected. Furthermore, the proposed exclusion for gas-fired units that burn oil during periods of gas curtailment, gas supply emergencies or for periodic testing of liquid fuel from the liquid subcategory would appear to be unworkable as drafted because it appears to only allow oil firing for 48 hours a year. As experience has repeatedly shown, natural gas curtailments due to hurricanes in the Gulf of Mexico will almost always exceed 48 hours. We assume the 48 hours was meant to apply only to the testing situation, and the draft language does not accurately represent the Agency intent. To address these two issues and the changes suggested in comment II.C.1, we recommend the following. These changes would also make this definition consistent with the gas subcategory definitions as suggested in Comment II.C.b.1.

Unit designed to that burns oil liquid subcategory includes any boiler or process heater that burnsed anymore than 10 percent liquid fuel, but less than 10 percent solid fuel on a heat input basis in the previous calendar yearon an annual average, either alone or in combination with gaseous fuels. Gaseous fuel boilers and process heaters that burn liquid fuel during periods of gas curtailment or, gas supply emergencies are not included in this definition. Gaseous fuel boilers and process heaters that burn liquid fuel or for periodic testing, of liquid fuel not to exceed a combined total of 48 hours during any calendar year, are not included in this definition.

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-2729.1, Excerpt Number 6 to view the response.

Commenter Name: Leonard W. Sandridge
Commenter Affiliation: University of Virginia
Document Control Number: EPA-HQ-OAR-2002-0058-2769.1
Comment Excerpt Number: 31

Comment: We recommend that the definition of wet scrubber be modified to include that there is an aqueous byproduct to be consistent with the operating limits imposed on this type of control device and with the definition of dry scrubber that references formation of a dry powder material. Our coal boilers are each equipped with a spray dry absorber (SDA) which injects a lime slurry with a dry power formed and collected in a baghouse. Our SDAs meet the definition of both a dry scrubber and wet scrubber as currently written, but the operating parameters for a wet scrubber do not apply.

Response: EPA has added a sentence in the final rule to read: “A wet scrubber creates an aqueous stream or slurry as a byproduct of the emissions control process.”

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-2702.1
Comment Excerpt Number: 72

Comment: C. EPA’s Proposed Definition of Gas 2 Units is Flawed.

EPA’s proposed definition for Gas 2 units does not include de minimus threshold. Therefore, under the Proposed Rule any use of gas other than natural gas or refinery gas will result in the imposition of emissions limits instead of work practices for the gas fired unit. Such a result is unreasonable and will result in the decreased use of off-gas and landfill gas. EPA has recently promoted the use of these alternative gases; therefore, such a result is clearly not in keeping with the agency’s overall goals and policy.

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-2960.1, Excerpt Number 27 to view the response.

Commenter Name: David A. Buff
Commenter Affiliation: Golder Associates Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2801.1
Comment Excerpt Number: 77

Comment: FSI has several comments on the definitions:

Bagasse boiler – see the FSI’s comments submitted to the docket on July 23, 2010.

Biomass fuel – consistent with comments submitted by FSI on the proposed rule regarding the Definition of Solid Waste, this definition should explicitly state that these materials are not solid wastes when burned as fuel in boilers or process heaters for energy recovery.

Boiler system – the “energy consuming systems” could be interpreted to reach well beyond the traditional boundaries of the boiler, since everything in a facility that uses steam could be considered as part of the boiler. This is beyond the authority of §112, which limits the scope of the rule to the "affected source".

Fuel type – in keeping with the request for a separate subcategory for bagasse boilers, it is requested that bagasse be listed as a specific fuel type. Just as there are different types of coal listed as specific fuel types (bituminous, subbituminous), so there are different types of biomass which are combusted differently in specially designed boilers. One of these biomass types is bagasse.

Unit designed to burn biomass subcategory – consistent with our previous comments, this definition should be revised to include all units which burn more than 10 percent biomass on an annual average heat input basis.

Unit designed to burn bagasse subcategory – consistent with our previous comments, this definition should be added to identify a separate subcategory for those units which burn more than 10 percent bagasse on an annual average heat input basis.

Temporary boiler – consistent with other related rules and the Clean Air Act (i.e., non-road engines), this definition should be revised to allow a boiler to remain at a location for up to 12 months and still be classified as a temporary boiler.

Response: EPA acknowledges the comment but did not update the definition of temporary boiler and any boiler that remains at a location for more than 180 consecutive days is no longer considered to be a temporary boiler.

The fuel type comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-2765.1, Excerpt Number 35 to view the response.

The temporary boiler comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-2960.1, Excerpt Number 21 to view the response.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 80

Comment: Tune-up is defined in proposed 63.7575 as Tune-up means adjustments made to a boiler in accordance with procedures supplied by the manufacturer (or an approved specialist) to optimize the combustion efficiency. However, 63.7540(a)(10) specifies what the work practice "tune-up" must include and that does not match the proposed definition. The proposed definition should be deleted.

Recommendation: Delete the proposed definition of “tune-up”.

Response: EPA has removed the definition from the final rule because it is covered in the rule language.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-2702.1
Comment Excerpt Number: 90

Comment: Liquid Fired Units
A. Definition of Units Designed to Burn Oil Should Be Amended.
The proposed definition of the subcategory of "units designed to burn oil." needs to be clarified. In the Proposed Rule, EPA defines the subcategory of "units designed to burn oil." as follows:

Unit designed to burn oil subcategory includes any boiler or process heater that burns any liquid fuel, but less than 10 percent solid fuel on a heat input basis on an annual average, either alone or in combination with gaseous fuels. Gaseous fuel boilers and process heaters that burn liquid fuel during periods of gas curtailment, gas supply emergencies or for periodic testing of liquid fuel not to exceed a combined total of 48 hours during any calendar year are not included in this definition. 75 FR 32065.

The proposed definition is unreasonable because, as it is currently phrased, gaseous fuel boilers and process heaters could be limited to only 48 combined total hours during a calendar year before they are included in this subcategory. EPA should clarify the "units designed to burn oil" subcategory to apply only to the time the unit is operated on oil for periodic testing of oil firing capability. EPA should impose no time limit on legitimate gas curtailment or gas supply emergencies. Such a change would be reasonable and better reflect EPA’s intent for units that burn liquid as evidenced by the "gas-fired boiler" definition in the Proposed Area Source Rule. 75 FR 31931.

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-2729.1, Excerpt Number 6 to view the response.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-2702.1
Comment Excerpt Number: 91

Comment: In the Proposed Area Source Rule, EPA defines gas-fired boiler as "any boiler that burns gaseous fuels not combined with any solid fuels, burns liquid fuel only during periods of gas curtailment, gas supply emergencies, or periodic testing on liquid fuel. Periodic testing of liquid fuel shall not exceed a combined total of 48 hours during any calendar year." 75 FR 31931. Notably, EPA imposes the 48 hour limitation only on the "[p]eriodic testing of liquid fuel" and there is no limit on legitimate gas curtailment or gas supply emergencies. Beyond consistency with the Proposed Area Source Rule, this rectification of the definition would be similar to EPA’s approach in the stationary SI internal combustion engine ("ICE") NSPS, where 50 hours are allowed for non-emergency use. See 40 C.F.R. 60.4243.

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-2729.1, Excerpt Number 6 to view the response.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-2702.1
Comment Excerpt Number: 92

Comment: B. CIBO Recommends that EPA Expand the Definition of Gaseous Fuel Fired Boilers and Process Heaters to Include Periods of Gas Curtailment when Backup Liquid Fuel Must be Fired.
Federal, state, or local governments and gas suppliers have in the past required a facility to curtail its use of natural gas so that it can be used for home heating or another critical need. The length of the curtailment usually lasts a very short time period during which the facility may either restrict production or switch to a liquid fuel to maintain the same level of production. These occurrences will only be taken in the national interest or for regional or local emergency type situations and only for a short time period. Onsite gas supply emergencies could also occur whereby use of gas fuel is not possible and backup liquid fuel firing is required in order to maintain critical production or services. Periods of backup fuel use would be limited to the time to complete repairs and safely return the gaseous fuel system to service.

CIBO requests that EPA expand the definition of gaseous fuel-fired boilers and process heaters to include gas curtailment required by a government agency (federal, state, local), natural gas supplier, or on-site gaseous fuel system emergencies. During the limited time of curtailment when the facility switches from gas to backup liquid fuel (recommended to be limited to 876 hours per year (10%)), new or reconstructed boiler and process heater affected sources would be exempt from complying with the liquid fuel standards (if they are included in the final rule). The exemption should allow for periodic backup fuel operation and testing in order to prove that it is available and reliable should it be needed; that testing time should be included within the 876-hour limit. In addition, this 10% annual time allowance would also allow for periodic operation on oil to allow turnover of oil in the storage tank to prevent oil degradation that might impact reliability when needed in an emergency. A facility should be able to apply to the permitting authority for an extension of the 876-hour exclusion if curtailments cause the unit to exceed that time limit.

Documentation of time firing backup fuel should be provided to the permitting authority by the affected source as part of the semi-annual reporting requirement. A review of California rules (i.e., Ventura County Rule 74.15; Kern Rule 435.2; Bay Area Rule 9.7; Santa Barbara Count Rule 342; Yolo-Solana Rule 2.27; South Coast Rule 1146; and SCAWMD Rule 1109) shows substantial relaxation of requirements in recognition of natural gas curtailments. Each of the California rules provides for less stringent limits when a normally gas-fired unit burns liquids - during a curtailment and while testing to assure operability on liquids in case a curtailment should occur.

If there is a curtailment of natural gas because of National interest, it is important as part of our National Energy Policy that refineries and petrochemical plants be allowed to continue production at the pre- curtailment levels so that there is a sufficient supply of home heating oil, jet fuel, diesel, gasoline, feedstocks, etc. If facilities are forced to limit production, the reduction in supplies may further intensify the problem because of the reduction in supply of products such as home heating oil, diesel, jet fuel, and gasoline. Similar issues exist at other critical manufacturing facilities.

The exemption would enable the facility to operate under the pre- curtailment gaseous fuel compliance requirements and thus be excluded from the liquid fuel requirements. Further, new or reconstructed units would not be required to install pollution control equipment required for liquid fuels which may never be used or only used for a very short time period over many years.

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-2729.1, Excerpt Number 6 to view the response.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 193

Comment: Table 6 provides for use of equivalent methods to those specified in the Table. Equivalent
methods is a defined term and the definition in 63.7575 is so restrictive as to be of little or no value. The definition should be revised to allow use of any analytical method that is shown to be equivalent to the cited EPA method using Part 63 Appendix A Method 301 or any method approved as equivalent by the appropriate permitting authority. Having EPA review and approve hundreds or thousands of such requests is a waste of EPA's and the sources time.

Recommendation: Revise the definition of “equivalent method” to include methods demonstrated by the source to be equivalent using Method 301 of Part 63 Appendix A.

Response: EPA acknowledges the comment but has retained the "or equivalent" terminology consistent with the proposed version.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-2702.1
Comment Excerpt Number: 213

Comment: Definition of Natural Gas.
EPA failed to use the definition of "Natural Gas" that represents the most current thinking of the agency. The definition adopted in § 60.41 Subpart Da, published in the Federal Register on 28th January 2009 (Federal Register /Vol. 74, No. 17 /Wednesday, January 28, 2009 /Rules and Regulations, p. 5079) includes an third definition of Natural Gas to read,

§ 60.41Da Definitions. Natural gas means:

(1) A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane; or

(2) Liquid petroleum gas, as defined by the American Society of Testing and Materials in ASTM D1835 (incorporated by reference, see § 60.17); or

(3) A mixture of hydrocarbons that maintains a gaseous state at ISO conditions. Additionally, natural gas must either be composed of at least 70 percent 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).

This third definition enables affected sources to burn gaseous fuels that are substantially similar to naturally occurring natural gas without being subject to a variety of additional requirements that impose a regulatory and cost burden on the source. The net impact of this third definition is to promote the beneficial combustion of clean gaseous fuels, such as clean Landfill Gas, which might otherwise be released into the atmosphere or flared. As EPA has indicated in its Landfill Methane Outreach Program (LMOP), The U.S. Environmental Protection Agency's Landfill Methane Outreach Program (LMOP) is a voluntary assistance program that helps to reduce methane emissions from landfills by encouraging the recovery and beneficial use of landfill gas (LFG) as an energy resource. LFG contains methane, a potent greenhouse gas that can be captured and used to fuel power plants, manufacturing facilities, vehicles, homes, and more.

http://www.epa.gov/lmop/

By failing to adopt the most current definition of "Natural Gas", as incorporated into § 60.41 Subpart Da, EPA is inhibiting sources from burning clean gaseous fuels like Landfill Gas that could be beneficially combusted. EPA should define "Natural Gas" to be identical to the definition in § 60.41Subpart Da.

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-2775.1, Excerpt Number 55 to view the response.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 238

Comment: Waste heat process heater is a defined term in proposed 63.7575, but the term is not used in the rule and this definition should be deleted.

Recommendation: Delete the definition of "waste heat process heater."

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-2775.1, Excerpt Number 58 to view the response.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 5

Comment: Some devices use electricity to heat water or produce steam. These are not generally thought of as enclosed combustion devices, but enclosed combustion is not a defined term and could be reinterpreted in the future.

Recommendation: Clarify that devices that use electricity to heat water or produce steam are not "boilers" under this proposal.

Response: See repsonse to comment EPA-HQ-OAR-2002-0058-2960.1, excerpt 2 for updates made to the definition of boiler within the final rule.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 8

Comment: Natural gas, as described in paragraph 1 of the proposed definition, must be separated from oil, production water, and solids and adjusted to pipeline specifications in production batteries and in natural gas plants. Thus, natural gas is generally processed to some degree prior to using as a fuel and thus might be construed as not being a naturally occurring mixture. Additionally, intermediate gas streams (i.e., gas streams that are separated from the hydrocarbon/water mixture removed from the ground that do not yet meet the pipeline quality natural gas specifications) are combusted in boilers and process heaters at the production site or the gas plant. Thus, we believe some clarification is needed in the definition of natural gas to be clear that processed and intermediate streams are included.

Recommendation: Clarify that gases derived from the "naturally occurring mixture found in geological formations" meets the definition of natural gas, as long as the principal constituent is methane, by revising proposed paragraph 1 as follows.

(1) A naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane, including intermediate gas streams generated during processing of natural gas at production sites or at gas processing plants; or

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-2775.1, Excerpt Number 55 to view the response.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 9

Comment: 63.7575 contains a definition for Unit designed to burn gas 2 (other), however the tables and some regulatory text do not use this term. They use the term other gas, which is not defined in the definitions section. It would reduce confusion if the rule language would be made consistent with the definition section or vice versa.

Recommendation: Replace the term "other gas" with "unit designed to burn gas 2 (other)", [Footnote: We suggest renaming this subcategory in Comment II.C.3.] throughout the rule and in the rule tables.

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-2960.1, Excerpt Number 27 to view the response.

Commenter Name: Robert P. Strieter
Commenter Affiliation: The Aluminum Association
Document Control Number: EPA-HQ-OAR-2002-0058-2711.1
Comment Excerpt Number: 2

Comment: The Aluminum Association requests that the Metal Processing Furnace definition be expanded to add the term "homogenizing furnaces" to the definition. Homogenizing furnaces are technically "annealing" furnaces, but adding this type of furnace to the definition will avoid potential issues with future applicability determinations. The final list will then encompass the full range of metal processing furnace operations included in our industry.

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-2967.1, Excerpt Number 5 to view the response.

Commenter Name: John Hopewell
Commenter Affiliation: American Coatings Association
Document Control Number: EPA-HQ-OAR-2002-0058-2886.1
Comment Excerpt Number: 26

Comment: The definition of natural gas should be revised to be consistent with the NSPS definition.

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-2775.1, Excerpt Number 55 to view the response.

Commenter Name: J. Michael Geers
Commenter Affiliation: Duke Energy
Document Control Number: EPA-HQ-OAR-2002-0058-2765.1
Comment Excerpt Number: 35

Comment: In 63.7575, the second sentence in the definition for "Coal" is incomplete. It states "Synthetic fuels derived from coal for the purposes of creating useful heat including, but not limited to, solvent-refined coal, coal-oil mixtures, and coal water mixtures, for the purposes of this subpart." It is not clear whether this sentence intends to include or exclude these materials from the definition of coal. This definition should be clarified.

Response: See preamble for discussion of new solid fuel subcategory. EPA has revised the second sentence of the definition to include synthetic fuels in the final rule.

Commenter Name: J. Michael Geers
Commenter Affiliation: Duke Energy
Document Control Number: EPA-HQ-OAR-2002-0058-2765.1
Comment Excerpt Number: 36

Comment: Duke Energy agrees with and supports the definition given in §63.7575 for “fuel type”. Specifically Duke Energy agrees that receiving fuel from different suppliers does not constitute and change in fuel type.

Response: The EPA thanks the commenter for their support of the definition for "fuel type."

Commenter Name: J. Michael Geers
Commenter Affiliation: Duke Energy
Document Control Number: EPA-HQ-OAR-2002-0058-2765.1
Comment Excerpt Number: 37

Comment: Duke Energy believes that EPA’s definition of a hot water heater is overly restrictive, or at best confusing. In §63.7575, EPA defines a Hot water heater as “a closed vessel with a capacity of no more than 120 U.S. gallons in whish water is heated by combustion of gaseous or liquid fuel... at pressures not exceeding 160 psig...” By this definition, regulated sources could include a very large number of hot water heaters used by offices, hospitals, schools, commercial businesses, and other non-industrial sources. Water could be used for bathing, dish washing, space heating and other similar purposes not associated with industrial

activities. While these types of hot water heaters are typically found at sources that are not considered major sources of HAPs, major source facilities sources can also have these types of hot water heaters. EPA should restrict the definition of a hot water heater for purposes of this rule to include only units that are specifically used as part of an industrial process. EPA should consider increasing the capacity of these units above 120 gallons.

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-2998.1, Excerpt Number 46 to view the response.

Commenter Name: Russ A. Wozniak
Commenter Affiliation: Dow Chemical Company
Document Control Number: EPA-HQ-OAR-2002-0058-2632.1
Comment Excerpt Number: 86

Comment: The Term “total rated heat input capacity” in the Definition for Waste Heat Boiler is Ambiguous and not used in Industry so it Should Be Clarified. The definition of "Waste heat boiler", copied below, refers to the “total rated heat input capacity” of the waste heat boiler.

There are essentially two sources of heat to a Waste Heat Boiler: waste heat from an energy source (e.g., gas turbine or internal combustion engine), and heat release from duct or supplemental burners. The waste heat from the energy source can vary with ambient temperature, atmospheric pressure and humidity. That variation affects the exhaust gas flow and temperature from the energy source. Changing flow and temperature result in different heat releases from the equipment. The Waste Heat Boiler manufacturer designs their equipment for the expected range of flows and temperatures, but does not specify a rated heat input value. Therefore, the phrase “total rated heat input capacity” is ambiguous because it is not established by the Waste Heat Boiler manufacturer. However, manufacturers of the energy source do establish accepted reference conditions.

The manufacturer of the energy source, such as a gas turbine manufacturer, recognizes that changing ambient conditions affects power output, waste heat flow and waste heat temperature. Therefore, the gas turbine industry establishes a specific reference for ambient conditions called ISO conditions (59°F, sea level, 60% relative humidity). The EPA use of the term “heat input” in the definition of Waste Heat Boiler should be based on reference conditions associated with the energy supplier to avoid ambiguity.

The heat release from the duct or supplemental burners is provided by the burner manufacturer. No additional clarification is required on heat input from the burners.

Dow suggests the following addition to the definition of Waste Heat Boiler:
Waste heat boiler means a device that recovers normally unused energy and converts it to usable heat. Waste heat recovery boilers incorporating duct or supplemental burners that are designed to supply 50 percent or more of the total rated heat input capacity of the waste heat boiler are not considered waste heat boilers, but are considered boilers. Waste heat boilers are also referred to as heat recovery steam generators. Use industry established reference conditions associated with the energy supplier for determining their rated heat release, such as ISO ratings for gas turbines.

Response: EPA has modifed the definition of waste heat boiler in the final rule so that it includes all waste heat boilers instead of considering only those units with 50 percent or more of their waste heat. Please refer to the response to comment EPA-HQ-OAR-2002-0058-2956.1, excerpt 1 or the final rule for updates to this definition.

Commenter Name: Russ A. Wozniak
Commenter Affiliation: Dow Chemical Company
Document Control Number: EPA-HQ-OAR-2002-0058-2632.1
Comment Excerpt Number: 87

Comment: EPA Should Modify the Definition of Tune-up to Reflect that it is a Process and Not a Procedure.

Boiler tune-up is a process, not a procedure. The combustion specialist knows how to adjust hardware or combustion control elements in order to improve combustion efficiency and maintain safety. That knowledge is based on training and experience consistent throughout the industry. There are too many variables involved in the adjustments that it would be near impossible to have written procedures to cover all possible tune-up adjustments. The specialist evaluates the 'as found' condition of the equipment, then applies his/her knowledge of appropriate adjustments to improve its performance.

The section on demonstrating continuous compliance recognizes that tuning is a process. Section 63.7540(a)(10)(i - vi) lists the elements to be covered during the tune-up process (e.g., burner inspection, flame pattern, air to fuel ratio, etc.).

Thus, the definition of tune-up should eliminate references to procedures, and Dow recommends the following revised definition:

Tune-up means adjustments made to a boiler, in accordance with industry combustion practices, that are performed procedures supplied by the manufacturer's representative or an approved specialist to optimize the combustion efficiency.

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-2960.1, Excerpt Number 80 to view the response.

Commenter Name: Jim Eubank
Commenter Affiliation: Kentucky Division of Air Quality
Document Control Number: EPA-HQ-OAR-2002-0058-3176.2
Comment Excerpt Number: 1

Comment: The definition for process heater in 40 CFR 60 Subpart D is completely different from the definition in 40 CFR 63 Subpart DDDDD. For consistency and clarification, these definitions need to be identified.

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-2960.1, Excerpt Number 13 to view the response.

Commenter Name: Kathryn M. Cunningham
Commenter Affiliation: Consumers Energy Company
Document Control Number: EPA-HQ-OAR-2002-0058-2904.1

Comment Excerpt Number: 1

Comment: There are two definitions for the liquid fuel burning units, it is unclear as to which one is correct re: "Liquid fuel subcategory" on Page 32064, and "Units designed to burn oil subcategory". Table 1 refers to this subcategory as "Units designed to burn liquid fuel". This seems erroneous as the subcategory shall be determined on an annual heat input basis, not design basis, as described in the definition. Consumers seeks further definition and clarity in this area.

Consumers has found that the emission limit proposed for carbon monoxide ("CO") for oil fired boilers is not achievable. Consumers has a permit to install a 65 mmBTU/hr distillate oil fired boiler. Consumers Energy has solicited five (5) well established U.S. manufacturers of package boilers to bid the package boiler and all were unanimous in not being able to meet the proposed regulation. Burners are typically designed for <50 PPM CO and <I OOPPM CO depending upon the application. There is no burner manufacturer that will design a burner to 1 PPM CO, as this will never be a feasible or cost effective goal in burner engineering. As a result of this proposed rule, Consumers has placed this installation project on hold and we are unable to proceed with installation of a much needed unit.

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-2863.1, Excerpt Number 54 to view the response.

Commenter Name: John Steber
Commenter Affiliation: Performance Fibers
Document Control Number: EPA-HQ-OAR-2002-0058-3174
Comment Excerpt Number: 2

Comment: Definitions — section 63.7575 [Period of natural pas curtailment or supply interruption]

Period of natural gas curtailment or supply interruption is defined as "a period of time during which the supply of natural gas to an affected facility is halted for reasons beyond the control of the facility. An increase in the cost or unit price of natural gas does not constitute a period of natural gas curtailment or supply interruption."
Many U.S. manufacturing facilities that utilize natural gas-fired boilers and process heaters, which also have the capability to burn alternative fuels, operate under contractual supply agreements with local utilities. The utilities offer these customers a reduced cost in natural gas in exchange for the ability to curtail the supply when the regional demand is high, typically during winter months, which in turn helps to prevent supply shortages to its other customers. During the contract period, natural gas supply may be curtailed at any time, which is in fact beyond the control of the facility. However, the establishment of the contract itself is technically not beyond the control of the facility.

1. PFI requests guidance and clarification on what is considered to be "reasons beyond the control of the facility" — This definition was added to the final vacated rule (69 FR 55218), presumably due to comments received based on the proposed rule (68 FR 1660) since it was not included in that document. However, PFI was unable to locate any information in the preamble to the final vacated rule or in this proposed rule related to the intent of the definition's meaning (i.e., no discussion on what is meant by "reasons beyond the control of the facility").

PFI assumes that is not the intent of the definition to include contractual arrangements with a supplier of natural gas as a reason that is in control of the facility, since virtually no facility that is subject to curtailment would meet the terms of this definition. However, PFI believes the intent should be clarified to help avoid ambiguity and misinterpretations, either by modification of the definition or in the form of a discussion in the preamble to the final rule, at a minimum. The following is a suggested modification to the definition based on the comments referenced in this section:

"Period of natural gas curtailment or supply interruption means a period of time during which the supply of natural gas to an affected facility is halted for reasons beyond the control of the facility. The act of entering into a contractual agreement with a supplier of natural gas established for curtailment purposes does not constitute a reason that is under the control of a facility for the purposes of this definition. An increase in the cost or unit price of natural gas does not constitute a period of natural gas curtailment or supply interruption."

Response: EPA has revised the definition in the final rule to match commenter's suggestion.

Commenter Name: Christian Richter
Commenter Affiliation: American Foundry Society
Document Control Number: EPA-HQ-OAR-2002-0058-2766.2
Comment Excerpt Number: 2

Comment: Definition of "Heat Input" Should Include Heat Captured from the Combustion of Process Off Gases

Process equipment with a direct fired fuel source to melt or otherwise convert raw materials into intermediate or finished products may generate off gases that are suitable to combust for heat recovery in either waste heat boilers or waste heat process heaters. The off gases from these processes contain both the products of combustion and reaction products from the raw materials and fuels utilized. These types of furnaces were not considered in the information collection request for development of the proposed Boiler MACT standard.

The types of waste heat boilers and process heaters surveyed as part of the information collection request for the Boiler MACT were either boilers firing fossil fuels or firing combustible by-products generated by the process. EPA considered the use of off gases to fire a boiler or process heater and exempted it from regulation, provided that the design of the boiler or process heater allowed no more than 50 percent of the heat energy could be obtained from the firing of supplemental fuels.

As a result, at least 50 percent of the heat input must come from combustion of process off gases. Nonetheless, EPA failed to include process off gas in the definition of fuels or in the definition of heat input.

The Boiler MACT data base from the boiler and process heater survey does not contain any process heaters that are fueled by by-product or off gas streams, but it does contain waste heat boiler applications for a variety of process types. It is good engineering practice to utilize process waste gas streams wherever practicable, especially when the gas streams have high heat value. Typically, the most effective uses of these waste gas streams are for heat recovery systems that are self contained within the process.

The definition for “heat input,” should include the heat captured from the combustion of the process off gases. Without this addition, there is no way to verify that the waste heat process heater is not an affected source regulated by Boiler MACT. Accordingly, EPA should amend the definition of “heat input” in 40 CFR § 63.7575 to include the following underlined text:

Heat input means heat derived from combustion of fuel or process off gas in a boiler or process heater system and does not include the sensible heat from preheated combustion air, re-circulated flue gases, or exhaust gases from other sources such as gas turbines, internal combustion engines, kilns, etc.

This clarification will clearly identify that the heat input used for determining the applicability of the waste heat boiler and waste heat process heater definitions can be calculated and clearly demonstrated. A definition that distinguishes sensible heat from the heat input in these systems is necessary for the determination of applicability as a waste heat unit.

Response: EPA has removed the following provision from the proposed definition of waste heat boiler "Waste heat recovery boilers incorporating duct or supplemental burners that are designed to supply 50 percent or more of the total rated heat input capacity of the waste heat boiler are not considered waste heat boilers, but are considered boilers." The final definition was revised to include all waste heat boilers. These changes were made to exempt the units it intended at proposal.

Commenter Name: Jim Eubank
Commenter Affiliation: Kentucky Division of Air Quality
Document Control Number: EPA-HQ-OAR-2002-0058-3176.2
Comment Excerpt Number: 2

Comment: The definitions for “boiler” in the proposed major source rule and area source rule are different. For consistency, EPA needs to clarify the two definitions.

Response: See response to comment EPA-HQ-OAR-2002-0058-2960.1, excerpt 2 for updates made to the definition of boiler within the final rule.

Commenter Name: Jim Eubank
Commenter Affiliation: Kentucky Division of Air Quality
Document Control Number: EPA-HQ-OAR-2002-0058-3176.2
Comment Excerpt Number: 3

Comment: One of the difficulties that the Division has encountered is the use of boilers/process heaters to provide heat to various processes at a source (dryers, steam press, etc.) using thermal oil. The source argued that when the boilers/process heaters stopped using thermal oil to transfer heat, and instead sent the combustion air to the dryers, the units were no longer boilers/process heaters but direct fired units. The boilers/process heaters were enclosed combustion devices used to recover thermal energy by sending the heat of combustion from one location at the facility to various other locations at the facility. Like steam, hot combustion air is a legitimate heat transfer medium. The only difference is that energy was delivered to other processes using a gas (air) instead of a liquid (thermal oil). The heat transfer medium should not matter. It is preferable that the term "heat transfer medium" be used (as it is defined in 40 CFR 60 Subpart D) to prevent this confusion. It is not the intention of the Division to incorporate direct-fired units into these regulations. But stand-alone combustion units with a controlled flame that are not directly tied to process equipment should be regulated as boilers/process heaters. The regulation needs to clarify the classification of units under these conditions.

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-2960.1, Excerpt Number 3 to view the response.

Commenter Name: Christian Richter
Commenter Affiliation: American Foundry Society
Document Control Number: EPA-HQ-OAR-2002-0058-2766.2
Comment Excerpt Number: 9

Comment: EPA should also consider the following for all natural gas-fired boilers and process heaters: EPA's definition of natural gas needs to be broader to account for non-geological origins of natural gas such as landfill gas, biogas, and synthetic gas derived from coal.

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-2775.1, Excerpt Number 55 to view the response.

Commenter Name: John Steber
Commenter Affiliation: Performance Fibers
Document Control Number: EPA-HQ-OAR-2002-0058-3174
Comment Excerpt Number: 10

Comment: Definitions — section 63.7575 [Process heaterl
Process heater is defined as "an enclosed device using controlled flame, that is not a boiler, and the unit's primary purpose is to transfer heat indirectly to a process material (liquid, gas, or solid) or to a heat transfer material for use in a process unit, instead of generating steam. Process heaters are devices in which the combustion gases do not directly come into contact with process materials. A device combusting solid waste, as defined in 40 CFR 241.3, is not a process heater. Process heaters do not include units used for comfort heat or space heat, food preparation for on-site consumption, or autoclaves."

PFI requests guidance and clarification on whether a batch-type pyrolysis oven/furnace that is used to remove (burn-off) hardened polymer from metal process parts (e.g., spinnerets, etc.) would meet the intent of this definition and thus be subject to this subpart. Typically, these types of ovens have a maximum rated heat input capacity of 0.5 MM BTU/hr or less.

Response: If the unit combusts solid waste, such as units that use high temperature to break the bond between the paint and the metal and then combust the paint flakes, leaving only ash, it is considered to combust solid waste, unless it qualifies as a metals recovery unit, and therefore not subject to the boiler and process heater standards. If it does not combust solid waste, such as units that only crack the bond at low temperatures where the paint flakes off of the metal and is collected, and thrown away, it would be subject to boiler MACT only if it is located at a major source. Since all of the units are small, it would be subject only to work practice standards under this standard.

Commenter Name: Kevin M. Dempsey
Commenter Affiliation: American Iron and Steel Institute
Document Control Number: EPA-HQ-OAR-2002-0058-2998.1
Comment Excerpt Number: 12

Comment: The definition of gas-fired boilers includes those units burning gaseous fuels, which by further definition includes process gases (e.g., coke oven gas, blast furnace gas, or basic furnace off-gas). However, the definition of gas-fired boiler is qualified by stating that gaseous fuels cannot be combined with any liquid fuel except during periods of gas curtailment, gas supply emergencies, or periodic testing on liquid fuels. Without clarification of that definition, the exemption for gas fired boilers is potentially negated.

While coke oven gas boilers are primarily designed to burn coke oven gas, usually with natural gas as a back-up fuel, they are sometimes supplemented with liquid fuels when the supply of coke oven gas from the coke oven process is interrupted due to operational difficulties or reduced operations necessitated by business conditions or when steam demands elsewhere in the plant that rely on steam from those boilers cannot be met by the available coke oven gas supply to the boilers. Similar circumstances can arise with blast furnace gas-fired boilers, e.g., during blast furnace relines, tuyere changes, or other temporary outages. It is not clear from the definition of gas-fired boiler whether the terms gas curtailment and gas supply emergencies pertain to commercial natural gas supplies or can be interpreted to include occasions of curtailment and supply deficiencies from the process supplying the gas to the boiler. In the absence of clarifying language in the definition, the occasional use of liquid fuel would place these boilers (as well as any units using any liquid fuel, except in the stated circumstances) into a category that requires stringent emission limits, the installation of costly emission control equipment, and testing, monitoring and recordkeeping obligations.

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-2764.1, Excerpt Number 14 to view the response.

Commenter Name: Kevin M. Dempsey
Commenter Affiliation: American Iron and Steel Institute
Document Control Number: EPA-HQ-OAR-2002-0058-2998.1
Comment Excerpt Number: 14

Comment: AISI requests that EPA provide clarification that boilers firing liquefied petroleum gas (LPG) or propane-derived synthetic natural gas (SNG) as a backup fuel are considered a gas-fired boilers. We note that EPA proposes to incorporate ASTM D183503a to define "natural gas" for purposes of this regulation. It is important that any standard incorporated by the regulation be broad enough to encompass the use of propane (a constituent of LPG) as natural gas and not just mixtures. Most LPG mixtures include butane, which reduces the effectiveness of LPG at low temperatures, causing many facilities to substitute propane. Propane (and/or LPG) is mixed with air to create SNG, which should be specifically allowed to be considered as natural gas for purposes of this rule. LPG-based SNG is often used for emergency backup and EPA should make this point explicit in the final rule.

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-2764.1, Excerpt Number 14 to view the response.

Commenter Name: Paul N. Cicio
Commenter Affiliation: Industrial Energy Consumers of America
Document Control Number: EPA-HQ-OAR-2002-0058-2752.1
Comment Excerpt Number: 16

Comment: EPA should also revise the definitions found on pages 32064-32065 of the Federal Register accordingly:

Minimum pressure drop means 90 percent of the minimum pressure drop during a normal cleaning cycle when operated according to the OEM recommended procedures.
Minimum scrubber effluent pH means 90 percent of at the minimum normal online load. Minimum normal online load shall be defined by the site based on unit load data and approved by the Administrator.
Minimum scrubber flow rate means 90 percent of the test average sorbent ratio during the most recent performance test demonstrating compliance with the applicable emission limit. The minimum sorbent ratio is defined by the site based on the amount and type of sorbent used to scrub acid gases, and may be based on whichever acid gas governs the normal sorbent injection rate (e.g., Ca:SO2, or Na:HCl, etc.). The minimum sorbent ratio must be approved by the Administrator.
Minimum sorbent injection rate means 90 percent of the test average sorbent (or activated carbon) injection ratio for each sorbent measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limits. The minimum sorbent ratio is defined by the site based on the amount and type of sorbent used to control emissions, and may be based on appropriate parameters to ensure optimal emissions control (e.g., lb carbon per MMacf, lb carbon per mmBtu heat input, etc.). The minimum sorbent ratio must be approved by the Administrator.

Minimum voltage or amperage means 90 percent of the test average voltage or amperage to the electrostatic precipitator measured according to Table 7 to this
subpart required to comply with Particulate Matter emission limits at the minimum normal online load. Minimum normal online load shall be defined by the site based on unit load data and approved by the Administrator.
Minimum voltage or amperage means 90 percent of the test average voltage or amperage to the electrostatic precipitator measured according to Table 7 to this subpart required to comply with Particulate Matter emission limits at the minimum normal online load. Minimum normal online load shall be defined by the site based on unit load data and approved by the Administrator.

Response: EPA has adjusted the terms in order to account for variable loads at the unit compared to the loads using during the performance test. See the modified definitions in the final rule.

Commenter Name: Jim Eubank
Commenter Affiliation: Kentucky Division of Air Quality
Document Control Number: EPA-HQ-OAR-2002-0058-3176.2
Comment Excerpt Number: 21

Comment: In the proposed rule EPA is proposing a work practice standard for boilers that burn natural gas or “refinery gas” (see Section III D. of the summary). The Division recommends that instead of identifying specificsources of the gases subject to the work practice requirements, EPA identify those qualities which would make a gas qualify (emission standards, possibly with periodic testing requirements to show that the gas continued to meet the requirements).

Response: EPA has revised the definition of natural gas, consistent with the boiler NSPS definition. Any unit burning any other gaseous fuels other than natural gas or refinery gas must demonstrate that the gases meet the specifications for mercury and H2S content. Please refer to the preamble for discussion of the Gas 1 subcategory work practice standards.

Commenter Name: Edward E. Quick
Commenter Affiliation: Celanese International Corp
Document Control Number: EPA-HQ-OAR-2002-0058-2840.1
Comment Excerpt Number: 25

Comment: The definition of a temporary boiler should not be limited to 180 consecutive days because it is inconsistent with well established EPA regulations for other temporary or portable equipment.
The definition of "temporary boiler" in the proposed rule limits the boiler to 180 consecutive days at a location. This definition is inconsistent with the definition in other regulations. Portable equipment is exempt from the requirements of the Mandatory Greenhouse Gas Reporting Rule in 40 CFR §98.30. In 40 CFR §98.6, portable is defined to include equipment is designed and capable of being carried or moved from one location to another (e.g. wheels, skids, carrying handles, dolly, trailer, or platforms) and the equipment resides at the same location for no more than 12 consecutive months. Furthermore, in Section 111(a)(3) of the Federal Clean Air Act, non-road engines defined in 40 CFR §89.2 are exempt from the definition of a stationary source provided that the engine is located on a site for a period of less than 12 consecutive months.
Boiler outages can exceed 6 months or 180 days and may require companies to acquire a temporary rental boiler. These rental boilers are brought onsite while repairs are made to the stationary boiler and are needed on an expedited delivery schedule. It is impractical to incorporate a temporary boiler into the existing control system during this short period.
Therefore, Celanese recommends that the definition of a temporary boiler be revised to allow the use of a temporary boiler onsite for a period of no more than 12 consecutive months, to allow for sufficient time to cover boiler outages and to be consistent with other EPA regulations.

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-2960.1, Excerpt Number 21 to view the response.
EPA has revised the definition in the final rule to match the definition of "portable" in the GHG reporting rule, as suggested by the commenter.

Commenter Name: Bruce A. Steiner
Commenter Affiliation: American Coke and Coal Chemicals Institute
Document Control Number: EPA-HQ-OAR-2002-0058-2849.1
Comment Excerpt Number: 31

Comment: EPA seeks to establish a definition for hot water heaters that would distinguish residential-type units or those used for non-process purposes from process-related units.

However, the proposed definition bases the exemption solely on the size and output of the unit by limiting the capacity of an exempted hot water heater to 120 gallons, the pressure to 160 psig, and the temperature to 120 °F.
In order to maintain consistency with the rationale used to exempt hot water heaters, a hot water heater should be distinguished from a boiler by the intended use of its output, not its physical parameters. Accordingly, ACCCI recommends the following revision to the definition in §63.7575:
Hot water heater means a device in which water is heated by combustion of gaseous or liquid fuel and is withdrawn for personal use and not for use in an industrial, commercial, or institutional process.

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-2998.1, Excerpt Number 46 to view the response.

Commenter Name: Kevin M. Dempsey
Commenter Affiliation: American Iron and Steel Institute
Document Control Number: EPA-HQ-OAR-2002-0058-2998.1
Comment Excerpt Number: 46

Comment: The Definition of Hot Water Heater Needs to be Revised

In section IV.A of the preamble to the Proposed Rule, EPA states that the proposal would not regulate hot water heaters as defined in section 63.7575. EPA recognizes that all hot water heaters meet the proposed definition of a boiler because they are enclosed devices that combust fuel for the purpose of heating water, but it is further stated that the when the hot water output from a hot water heater is intended for personal use rather than for use in an industrial, commercial, or institutional process, the hot water heater is more appropriately identified as a residential-type boiler and not an industrial, commercial, or institutional boiler.

EPA seeks to establish a definition for hot water heaters that would distinguish residential-type units or those used for non-process purposes from process-related units. However, the proposed definition bases the exemption solely on the size and output of the unit by limiting the capacity of an exempted hot water heater to 120 gallons, the pressure to 160 psig, and the temperature to 120 degrees F.

In order to maintain consistency with the rationale used to exempt hot water heaters, a hot water heater should be distinguished from a boiler by the intended use of its output, not its physical parameters. Accordingly, AISI recommends the following revision to the definition in section 63.7575:

Hot water heater means a device in which water is heated by combustion of gaseous or liquid fuel and is withdrawn for personal use and not for use in an industrial, commercial, or institutional process.

Response: EPA has revised the definition in the final rule to match the one suggested in this comment.

Commenter Name: Christopher S. Colman
Commenter Affiliation: Hovensa LLC
Document Control Number: EPA-HQ-OAR-2002-0058-2863.1
Comment Excerpt Number: 54

Comment: Proposed Rule Language:
Liquid fuel subcategory includes any boiler or process heater of any design that burns more than 10 percent liquid fuel and less than 10 percent solid fuel, on an annual heat input basis.
Unit designed to burn oil subcategory includes any boiler or process heater that burns any liquid fuel, but less than 10 percent solid fuel on a heat input basis on an annual average, either alone or in combination with gaseous fuels. Gaseous fuel boilers and process heaters that burn liquid fuel during periods of
gas curtailment, gas supply emergencies or for periodic testing of liquid fuel not
to exceed a combined total of 48 hours during any calendar year are not included in this definition.
Comment:
It is unclear from these definitions whether a unit that burns ANY oil is subject to regulation as an oil burning unit or whether a 10% threshold applies. As noted in HOVENSA's comments above, HOVENSA disagrees with the technical basis for the 10% threshold.

Response: EPA has revised the definition in the final rule from "oil" to "liquid fuel."

Commenter Name: Traylor Champion
Commenter Affiliation: Georgia-Pacific LLC
Document Control Number: EPA-HQ-OAR-2002-0058-2745.1
Comment Excerpt Number: 64

Comment: EPA has been very consistent throughout the proposal to use 10% as a threshold for movement from one subcategory to another. For example the most stringent – coal – includes units that burn at least 10% coal. The next – biomass – includes units that burn at least 10% biomass and less than 10% coal. The first sentence of the oil (liquid) subcategory includes any liquid fuel, but less than 10 % solid fuel.

Therefore, it logically follows that a plain reading of the Gas 1 subcategory would be that EPA intended to include any unit that burns at least 90% gas and less than 10% of any other fuel. However, the second sentence in the oil (liquid) subcategory emphasized above is in contradiction with the Gas 1 definition by implying that any more than 48 hours (2 days) per year of liquid fuel firing would reclassify the unit into the liquid category.

GP urges EPA to delete the sentence in the definition of an oil (liquid) unit: “Gaseous fuel boilers and process heaters that burn liquid fuel during periods of gas curtailment, gas supply emergencies or for periodic testing of liquid fuel not to exceed a combined total of 48 hours during any calendar year are not included in this definition”.

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-2729.1, Excerpt Number 6 to view the response.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 224

Comment: The Definition Of Natural Gas Should Be Revised To Be Consistent With The NSPS Definition The proposed section 63.7575 definition of natural gas includes only the prior NSPS definition, not the 2009 NSPS Subparts Db and Dc revisions. The natural gas definition for this rule needs to be consistent with that rule and should, therefore, also include the following: "(3) A mixture of hydrocarbons that maintains a gaseous state at ISO conditions. Additionally, natural gas must either be composed of at least 70 percent 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)." The addition of item 3 in the definition allows other gases that are essentially the same as natural gas, such as synthetic natural gas or treated landfill gas, to be included in the definition. It is unnecessary to restrict the definition to only gases from geologic formations. The net impact of this third part of the definition is to promote the beneficial combustion of clean gaseous fuels, such as clean Landfill Gas, which might otherwise be released into the atmosphere or flared.

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-2775.1, Excerpt Number 55 to view the response.

Commenter Name: Kevin M. Dempsey
Commenter Affiliation: American Iron and Steel Institute
Document Control Number: EPA-HQ-OAR-2002-0058-2998.1
Comment Excerpt Number: 13

Comment: If the qualification of liquid fuel usage remains in the definition of gas-fired boiler, we suggest adding further clarifying language that is contained in the definition of a waste heat boiler in the Proposed Rule. Waste heat boilers are exempt from the rule. The waste heat boiler definition in the Proposed Rule is limited to units designed to use no more than 50% of the total heat input capacity of the unit with supplemental burners. We believe that the environmental and energy conservation benefits of using coke oven gas are comparable to the use of waste heat or blast furnace gas, both exempted under the Proposed Rule, and that the same provisions for using supplemental fuels should apply to units intended to utilize coke oven gas. Accordingly, applying the same rationale, we urge EPA to modify the gas-fired boiler exemption to include those units designed to use supplemental fuels up to 50% of the total heat input capacity of the unit.

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-2960.1, Excerpt Number 27 to view the response.

Rule Language: Definitions (new)

Commenter Name: Arlington Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1779
Comment Excerpt Number: 127

Comment: There’s no definition of what back-up fuel is, so they can use back-up fuel for 90 percent of their operations and their primary fuel for 10 percent of their operations. And that’s a real problem that we believe needs to be corrected.

Response: See final rule and preamble for discussion of how units are assigned to subcategories and provisions available to switch subcategories.

Commenter Name: David A. Buff
Commenter Affiliation: Golder Associates
Document Control Number: EPA-HQ-OAR-2002-0058-1841.1
Comment Excerpt Number: 1

Comment: The Florida Sugar Industry proposes a regulatory definition for “bagasse boiler” as follows:
Bagasse boiler means a hybrid suspension- and grate/floor-fired boiler that is uniquely designed and operated to dry and burn bagasse as its primary fuel. The steam output from the boilers is tied directly to the sugarcane grinding mills, electrical generators, and the raw sugar production process for combined heat and power generation. Bagasse boilers receive bagasse fuel directly and continuously from the sugarcane milling and grinding process. Fuel distributors specially designed for bagasse are used in conjunction with air distributors to
spread the fuel material over the boiler width and depth. The drying and much of the combustion of the fuel takes place in suspension, and the combustion is completed on the grate or floor. Bagasse boilers are universally designed to have high heat release rates and high excess air rates.

Response: Please refer to the preamble for discussion of a combined grate/suspension firing subcategory. This subcategory includes bagasse units however is based on design features, and is not specific to fuel type. Bagasse boilers that have a fuel cell combustor design will be covered under the fuel cell category,

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Commenter Name: Robin Mills Ridgway
Commenter Affiliation: Purdue University
Document Control Number: EPA-HQ-OAR-2002-0058-2782.1
Comment Excerpt Number: 10

Comment: EPA Should Clarify Definition of Units Burning Single Type of Fuel

Units that burn a single fuel and choose to comply via stack testing are not required to conduct fuel analyses. This exemption from performing fuel analysis is not clear however, because the definition of units burning a single fuel needs to be clarified. Purdue asks that EPA define "units burning a single type of fuel" to include those that burn only one type of solid fuel but use gaseous or liquid fuel as start-up/supplemental fuels.

Purdue’s solid fuel fired boilers cannot start up from a cold condition on their main fuel. In addition, the stokers can co-fire a nominal amount of natural gas during operation for flame stability. These units require an additional fuel source to initiate combustion until such time as the unit is warmed up and stable combustion with the solid fuel can be safely maintained. Whether for startup, short-term flame stability when solid fuel feeding and/or when firing systems are taken in- or out-of-service, or in reaction to unusual conditions, the startup or supplemental fuel is a transient fuel source. The start up or supplemental fuel represents a negligible percentage of the source’s total hours of operation, and thus has a negligible impact on overall emissions from the source.

We support EPA’s intent to exempt units that fire a single type of fuel from the additional burden of conducting fuel analyses during performance stack testing as a reasonable accommodation to minimize unnecessary costs. EPA should clarify its intent in this matter by including language to explain that units which use a start-up fuel for initial startup, units shutdown, or transient flame stability purposes, still qualify as “sources that burn a single type of fuel” and are exempt from the fuel analysis requirements under §63.7521 and Table 6.

EPA should further clarify that solid fuel units that fire Natural Gas or Commercial Fuel Oil as a supplementary or start up fuel are likewise considered “sources that burn a single type of fuel” and are exempt from the fuel analysis requirements under §63.7521 and Table 6.

Response: Please refer to the preamble for discussion of startup/shutdown changes. Revised 63.7510(a) to add that sources using a second fuel for only start up, shut down, and transient flame stability are still considered units burning a single fuel.

Commenter Name: Myra C. Reece
Commenter Affiliation: South Carolina Department of Health and Environmental Control
Document Control Number: EPA-HQ-OAR-2002-0058-2525.1
Comment Excerpt Number: 12

Comment: Define Maximum Normal Operating Load

The EPA proposes that facilities conduct yearly performance tests for the first three years for affected sources that elect to demonstrate compliance with any of the emission limits through performance testing. Facilities could establish an every three-year schedule if the performance tests for the pollutant show that emissions are at or below 75 percent of the emission limit for at least 3 consecutive years. This reduced testing option does not apply to performance tests for dioxin/furan or if the facility elects to demonstrate compliance using the emission averaging option.

The EPA proposes that affected sources conduct performance tests at the "maximum normal operating load." However, this maximum normal operating load is not defined in the proposed rule. Facilities use different fuels depending on many variables such as availability and cost. Fuels are also combusted in different proportions throughout the year. The EPA should provide a clear definition of maximum normal operating load in 63.7575. The EPA should also clearly define how a source that utilizes more than one fuel should comply with this requirement. Having this clearly defined is necessary not for only determining compliance with the emission standards, but also for adequately approving site-specific test plans that would be required in 63.7520.

Response: EPA has revised the final rule by replacing "maximum operating load" with "representative operating load conditions."

Commenter Name: Myra C. Reece
Commenter Affiliation: South Carolina Department of Health and Environmental Control
Document Control Number: EPA-HQ-OAR-2002-0058-2525.1
Comment Excerpt Number: 19

Comment: Define Approved Specialist

In 63.7575, a tune-up is defined as "adjustments made to a boiler in accordance with procedures supplied by the manufacturer (or an approved specialist) to optimize the combustion efficiency". "Approved specialist" must be defined in order to determine who can establish procedures to optimize the combustion efficiency in absence of manufacturer’s recommendations. We believe the EPA should retain the authority to determine whether an individual qualifies as an "approved specialist" and should provide a clear process for these individuals to be approved.

Response: EPA has removed the definition of "Tune up", so "Aaproved specialist" definition is not needed.

Commenter Name: Myra C. Reece
Commenter Affiliation: South Carolina Department of Health and Environmental Control
Document Control Number: EPA-HQ-OAR-2002-0058-2525.1
Comment Excerpt Number: 20

Comment: Define What Constitutes A Limited-Use Boiler

In 63.7555(d)(3), the EPA proposes that records of monthly hours of operation by each boiler or process heater must be maintained and that this requirement only applies to limited-use boilers and process heaters. A definition of limited-use boilers should be included in 63.7575.

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-2960.1, Excerpt Number 244 to view the response.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 284

Comment: The proposed standard at 63.7520(c) requires that performance tests be conducted at “the maximum normal operating load….”. However, “normal” is not defined in the proposed standard. In the absence of a definition, “normal” can mean almost anything to an owner/operator, or to a regulatory agency. To insure that tests are conducted under reasonably consistent operating conditions across the regulated boiler universe, EPA should define “normal” to mean “between 90% and 110% of the average operating rate during the preceding 12 months.” Because some state agencies ordinarily require operating boilers at or near capacity, conducting full-load emission tests on boilers that normally operate at sub-capacity loading will be non-representative of truly normal conditions on that boiler.

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-2525.1, Excerpt Number 12 to view the response.

Commenter Name: Donald R. Schregardus
Commenter Affiliation: Department of Defense
Document Control Number: EPA-HQ-OAR-2002-0058-2763.1
Comment Excerpt Number: 1

Comment: EPA should use consistent terminology and define terms where necessary in the final rule.

In the proposed rule, EPA uses three different terms in providing details on how to properly categorize a regulated boiler into the proper subcategory:

-In the preamble(§III.D, page 32012): "If your new or existing boiler or process heater burns gaseous fuel and less than 10 percent, on an annual average heat input basis, of liquid or solid fuel, we are proposing that the unit is in one of the gas subcategories."
This phrase "annual average heat input basis" is also used in the preamble when defining the other source categories.

-In §63.7575, the proposed definitions for units designed to burn biomass, coal, gas I (NG/RG) and oil use the phrase "heat input basis on an annual average".

-In §63.7575, the proposed definition for liquid fuel subcategory uses the phrase "annual heat input basis."

If the term -annual average heat input basis" is chosen, EPA should define or explain the term. We believe that EPA intends for this determination to be done for a calendar year thus the term "average" could be misleading. If the intent is for facilities to average fuel use over multiple years, then EPA should specify the number of years to include in the average.

Recommend EPA adopt the term "annual heat input basis" for consistent use throughout the rule.

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-2761.1, Excerpt Number 1 to view the response.

Commenter Name: Walter Tyler
Commenter Affiliation: Invista
Document Control Number: EPA-HQ-OAR-2002-0058-2761.1
Comment Excerpt Number: 1

Comment: INVISTA requests that EPA further clarify the meaning of the phrase “heat input basis on an annual average.” As currently drafted, the language could be interpreted to mean a subject facility would have to calculate the annual average each year, which is inconsistent with similar requirements in existing Clean Air Act regulations. For example, the New Source Performance Standards, Subpart Db, uses the term “annual capacity factor” to limit the applicability of an emission limit, which is nearly an identical purpose to the use of the “heat input basis on an annual average” term in the above definition. See 40 CFR 60.42b(f). The meaning should be clarified in this proposed regulation by adopting the same approach.

Specifically, EPA should define “annual capacity factor” and replace the phrase “heat input basis on an annual average.” INVISTA proposes the following text:

Recommended Text in 63.7575, Definitions:
Annual capacity factor means the ratio between the actual heat input to a unit subject to this subpart, as applicable, during a calendar year and the potential heat input to the unit had it been operated for 8,760 hours during a calendar year at the maximum steady state design heat input capacity. In the case of units that are rented or leased, the actual heat input shall be determined based on the combined heat input from all operations of the affected facility in a calendar year.

Unit designed to burn gas 1 (NG/RG) subcategory includes any boiler or process heater that burns at least 90 percent natural gas and/or refinery gas with at least a 90 percent annual capacity factor on a heat input basis on an annual average.

Unit designed to burn gas 2 (other) subcategory includes any boiler or process heater that burns gaseous fuels other than natural gas and/or refinery gas not combined with any solid or liquid fuels at less than a 10 percent annual capacity factor.

Response: EPA has revised the final rule language in multiple areas to clarify when heat input is is needed as an average, a fraction or percent, or as the total input.

Commenter Name: Mike D. Craig
Commenter Affiliation: New Energy Corp.
Document Control Number: EPA-HQ-OAR-2002-0058-2695.1
Comment Excerpt Number: 2

Comment: Proposed 40 C.F.R. § 63.7520(c) states that the performance stack test must be performed
at maximum normal operating load. How is maximum normal operating load defined?

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-2525.1, Excerpt Number 12 to view the response.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 6

Comment: Boilers and process heaters that use natural gas or refinery gas as fuel are subject to different requirements from units that use other gases. If this situation remains in the final rule, refinery gas needs to be defined. We recommend the following definition, which we feel is most likely to reflect the fuels fired by the units identified as firing refinery gas in the rulemaking database.

Refinery gas means any gas which is generated at a petroleum refinery and which is combusted. Refinery gas includes natural gas when the natural gas is combined and combusted in any proportion with a gas generated at a refinery. Refinery gas includes gases generated from other facilities when that gas is combined and combusted in any proportion with gas generated at a refinery.

Including gases from contiguous and nearby facilities reflects the real situation at many refineries, where adjoining petrochemical operations, natural gas plants, terminal operations, third party hydrogen plants, electric utility plants, etc. have common fuel gas systems with a refinery. This is consistent with the definition of fuel gas in the Refinery 1 NESHAP (Part 63 Subpart CC).

The fact that this definition is meant to include gases from adjoining operations was made clear in the Final Background Information Document for Subpart CC, where EPA states the following in response to comments received. [Footnote: US EPA, Emission Standards Division, National Emission Standards for Hazardous Air Pollutants, Petroleum Refineries Background Information for Final Standards, Summary of Public Comments and Responses, EPA-453/R-95-015b, July 1995]

On page 5-41[A1]

Response: The EPA agrees that refineries and petrochemical plants with a common fuel gas system should be accounted for in the definition of fuel gas system. The EPA contents that this is accomplished with the wording “offsite and onsite piping and control system”. The reference to “external sources of natural gas or liquefied petroleum gas” was meant to include in the definition other sources of gas, such as natural gas or liquefied petroleum gas, supplied by a vendor. It is not intended as a reference to adjacent petrochemical plants. However, the words underlined by the commenter have been deleted to avoid confusion. The EPA contends that the definition does not exclude fuel gas systems associated with petrochemical plants.

On Page 5-42
Response: The EPA agrees that it should be recognized that refineries may share a fuel gas system with an adjacent non-refinery plant. This is accomplished in the definition of fuel gas-system, which includes the “offsite and onsite piping control system.” The EPA contends that it is not necessary to revise the definition of refinery fuel gas. The definition of miscellaneous process vents excludes “gaseous streams to a fuel gas system.” It is in the definition of fuel gas system that the inclusion of petrochemical and other facilities must be made.

Recommendation: Add a definition of refinery gas as suggested herein.

Response: EPA has revised the final rule to include a definition of refinery gas as suggested by the commenter.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-2702.1
Comment Excerpt Number: 85

Comment: EPA Should Clarify Definition of Units Burning Single Type of Fuel.
Units that burn a single fuel and choose to comply via stack testing are not required to conduct fuel analyses. 75 FR 32051. This exemption from performing fuel analysis is not clear and the definition of units burning single fuel needs to be revised. CIBO recommends that EPA define "units burning a single type of fuel" to include those that burn only one type of solid fuel but use gaseous or liquid fuel as start-up/supplemental fuels.

Most solid fuel boilers cannot start up from a cold condition on their main fuel. Such units require an additional fuel source to initiate combustion until such time as the unit is warmed up and stable combustion with the solid fuel can be safely maintained. For example, pulverized coal fired boilers typically start up by firing either Natural Gas or Fuel Oil. Startup periods typically last from several hours (e.g. stoker coal or pulverized coal boilers) to several days (e.g. large circulating fluidized bed boilers), per OEM recommendations, during which time coal combustion is started. When certain OEM specified conditions are met (e.g., minimum steam temperature, minimum tube temperature, minimum flue gas temperature, minimum pulverizer temperature, elapsed time from light-off, etc.), the start up fuel is shut down and the unit fires coal exclusively. Some pulverized coal units have additional OEM specified flame stability controls that require the start up fuel to be fired on specific burners when a pulverizer is either being removed from service or put into service (e.g., typical pulverized coal fired boilers). Solid fueled units can also utilize the startup fuel to preserve unit capacity due to an unforeseen malfunction in the solid fuel feeding and/or firing system(s). Whether for startup, short-term flame stability when solid fuel feeding and/or firing systems are taken in- or out-of-service, or in reaction to unusual conditions, the startup or supplemental fuel is a transient fuel source. The start up or supplemental fuel represents a negligible percentage of the source’s total hours of operation, and thus has a negligible impact on overall emissions from the source. For example, if a source operates continuously on coal for 49 weeks per calendar year; and has three start ups per year, each of which requires firing Natural Gas for 8 hours; the annual source operating time on Natural Gas equals (3 x 8 hours = 24 hours) divided by (49 weeks x 7 days per week x 24 hours per day = 8,232 hours) equaling 0.3% of the source’s operating hours on the startup fuel. The percentage of operating hours with supplemental fuel will necessarily vary based on unit design, operating characteristics, fuel quality, and other issues.

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-2782.1, Excerpt Number 10 to view the response.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 244

Comment: Proposed 63.7555(d)(3) requires “You must keep records of monthly hours of operation by each boiler or process heater. This requirement applies only to limited-use boilers and process heaters.” “Limited-use” is not a defined term. We presume this means boilers and process heaters that do not normally operate, but only operate intermittently. Thus, units that operate in standby mode, i.e., at low rates until needed, would not be “limited use” units. Additionally, it should be clarified that occasional outages for maintenance, production adjustments, etc, do not make a unit “limited use.”

Recommendation: Clarify the meaning of “limited use” as discussed above.

Response: Please refer to the preamble for discussion of the limited-use subcategory. EPA adapted the definition of “limited use solid fuel subcategory” from 2004 vacated rule to read as follows: Limited-use boiler or process heater means any boiler or process heater that burns any amount of solid, liquid, or gaseous fuels, has a rated capacity of greater than 10 MMBtu per hour heat input, and has a federally enforceable annual average capacity factor of no more than 10 percent.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-2702.1
Comment Excerpt Number: 86

Comment: We support EPA’s intent to exempt units that fire a single type of fuel from the additional burden of conducting fuel analyses during performance stack testing as a reasonable accommodation to minimize unnecessary costs. EPA should clarify its intent in this matter by including language to explain that units which require a start-up fuel for initial startup, units shutdown, or transient flame stability purposes, still qualify as "sources that burn a single type of fuel" and are exempt from the fuel analysis requirements under §63.7521 and Table 6.

EPA should further clarify that solid fuel units that fire Natural Gas or Commercial Fuel Oil as a supplementary or start up fuel are likewise considered "sources that burn a single type of fuel" and are exempt from the fuel analysis requirements under §63.7521 and Table 6.

Response: The rule has been revised to consider units that use supplementary fuel only for startup, shutdown, and flame stability are still considered to burn only a single fuel. Please refer to the preamble for discussion of startup/shutdown changes.

This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-2782.1, Excerpt Number 10 to view the response.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 96

Comment: Based on 63.1(a)(10) of part 63 subpart A, a day is a calendar day unless otherwise specified. Thus we assume the 30-day rolling average specified for CO from boilers and process heaters ?100 MMBTU/hr means an average must be calculated once per day for the 30 calendar day period ending at midnight of the previous day. It would be wasteful and add no value to require more frequent calculations than that, since the intent is to average the CO emissions over 30 days.

Recommendation: Clarify that the CO 30-day rolling average is based on 30 calendar days.

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-2863.1, Excerpt Number 51 to view the response.
EPA has removed the 30-day rolling average compliance mechanism from the final rule. We have also added a definition of operating day in the final rule.

Commenter Name: John Hopewell
Commenter Affiliation: American Coatings Association
Document Control Number: EPA-HQ-OAR-2002-0058-2886.1
Comment Excerpt Number: 27

Comment: If refinery gas will be regulated separately from other gases in the final rule, EPA should include a definition of refinery gas.

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-2960.1, Excerpt Number 6 to view the response.

Commenter Name: Russ A. Wozniak
Commenter Affiliation: Dow Chemical Company
Document Control Number: EPA-HQ-OAR-2002-0058-2632.1
Comment Excerpt Number: 8

Comment: The term refinery gas is not a defined term in the proposed MACT rule for boilers and heaters. However, a definition of Refinery Fuel Gas is published in 40 CFR 63.641 as follows:

Refinery Fuel Gas means "a gaseous mixture of methane, light hydrocarbons, hydrogen, and other miscellaneous species (nitrogen, carbon dioxide, hydrogen sulfide, etc.) that is produced in the refining of crude oil and/or petrochemical processes and that is separated for use as a fuel in boilers and process heaters throughout the refinery."

In conjunction with the definition of "Unit Designed to Burn Gas 1 (NG/RG)", Dow suggests the following definition to add to the regulatory text in Section 63.7575:

Refinery Gas and Off-Gas Streams from Petrochemical and Chemical Plant processes - means "a gaseous mixture of methane, light hydrocarbons, hydrogen, and other miscellaneous species (nitrogen, carbon dioxide, hydrogen sulfide, etc.) in the refining of crude oil or in the production of chemicals or petrochemicals and that is separated for use as a fuel in boilers and process heaters throughout the site.

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-2960.1, Excerpt Number 6 to view the response.

Commenter Name: John Hopewell
Commenter Affiliation: American Coatings Association
Document Control Number: EPA-HQ-OAR-2002-0058-2886.1
Comment Excerpt Number: 20

Comment: EPA should define maximum normal operating load

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-2525.1, Excerpt Number 12 to view the response.

Commenter Name: Stephen V. Capone
Commenter Affiliation: SABIC Innovative Plastics US LLC
Document Control Number: EPA-HQ-OAR-2002-0058-2861.1
Comment Excerpt Number: 6

Comment: A determination of whether an emission unit is equipped with a dry control system is one of the steps in determining compliance requirements pursuant to proposed §63.7541(a)(2). The definitions in 63.7575 do not include a definition of "dry control system". The definitions do include "dry scrubber", "electrostatic precipitator", and "fabric filter", but do not define each of

those control techniques to be a "dry control system". EPA should clarify the rule by changing the definitions as follows (additions underlined in bold):
Dry scrubber means an add-on air pollution control system that injects dry alkaline sorbent (dry injection) or sprays an alkaline sorbent (spray dryer) to react with and neutralize acid gas in the exhaust stream forming a dry powder material. Sorbent injection systems in fluidized bed boilers and process heaters
are included in this definition. A dry scrubber is a dry control system.
Electrostatic precipitator means an add-on air pollution control device used to capture particulate matter by charging the particles using an electrostatic field, collecting the particles using a grounded collecting surface, and transporting the particles into a hopper. An electrostatic precipitator is a dry coritroi system.
Fabric filter means an add-on air pollution control device used to capture particulate matter by filtering gas streams through filter media, also known as a baghouse. A fabric filter is a dry control system.

Response: EPA has added to the final rule that dry scrubbers, ESP, and FF are "dry control systems."

Commenter Name: Barry Christensen
Commenter Affiliation: Occidental Chemical Corp
Document Control Number: EPA-HQ-OAR-2002-0058-2848.1
Comment Excerpt Number: 4

Comment: EPA Should include a definition for “refinery gas” since units fired with refinery gas are included in the Gas 1 subcategory definition (63.7575). OCC noted that two refineries in the rulemaking database are firing 100% hydrogen. The fuel gas definition should include hydrogen generated by chemical manufacturing facilities in a manner similar to how fuel gas systems are addressed in the refinery MACT. This is consistent with the definition of fuel gas in the Refinery 1 NESHAP (Part 63, Subpart CC). In that standard, “refinery fuel gas” and “refinery fuel gas system” are defined as follows: “Refinery fuel gas means a gaseous mixture of methane, light hydrocarbons, hydrogen, and other miscellaneous species (nitrogen, carbon dioxide, hydrogen sulfide, etc.) that is produced in the refining of crude oil and/or petrochemical processes and that is separated for use as a fuel in boilers and process heaters throughout the refinery.”

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-2960.1, Excerpt Number 6 to view the response.

Commenter Name: Steven G. Hanson
Commenter Affiliation: Graphic Packaging International
Document Control Number: EPA-HQ-OAR-2002-0058-2723.1
Comment Excerpt Number: 25

Comment: What does EPA intend by "maximum normal operating load"? Is this intended to be maximum operating capacity of the unit or "typical" (i.e, normal) operations? Does normal mean annual average or short-term maximum? This term is unclear and is not defined in the proposed regulation.

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-2525.1, Excerpt Number 12 to view the response.

Commenter Name: Christopher S. Colman
Commenter Affiliation: Hovensa LLC
Document Control Number: EPA-HQ-OAR-2002-0058-2863.1
Comment Excerpt Number: 51

Comment: Proposed Rule Language §63.7525(a)(5):
“You must calculate and record a 30-day rolling average emission rate on a daily basis. A new 30-day rolling average emission rate is calculated as the average of all of the hourly CO emission data for the preceding 30 operating days.”
Comments:
The proposed rule does not specifically define “operating day”.

Response: EPA has added a definition to the final rule adapted from the NSPS definition of "operating day."

Commenter Name: Christopher S. Colman
Commenter Affiliation: Hovensa LLC
Document Control Number: EPA-HQ-OAR-2002-0058-2863.1
Comment Excerpt Number: 52

Comment: Proposed Rule Language §63.7525(b)(4):
“Obtain valid CEMS hourly average for all operating hours on a 30-day rolling average basis.....”
Comments:
The proposed rule does not specifically define “valid hourly average”.

Response: EPA has added rule language at 63.7525(b)(4) within the final rule and a definition in 63.7575 to explain what is meant by valid hourly average.

Commenter Name: Lee B. Zeugin
Commenter Affiliation: Utility Air Regulatory Group

Document Control Number: EPA-HQ-OAR-2002-0058-2880.1
Comment Excerpt Number: 73

Comment: Proposed § 63.7525 requires units with CO CEMS to calculate and record 30-day rolling average emission rate on a daily basis. A new 30-day rolling average is calculated as the average of all hourly CO emissions data for the preceding 30 “operating days.” Proposed § 63.7525(a)(5). However, the term “operating day” is not defined in the proposed rule or in 40 C.F.R. § 63.2.

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-2863.1, Excerpt Number 51 to view the response.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 197

Comment: EPA Should Define Maximum Normal Operating Load. The proposed standard at section 63.7520(c) requires that performance tests be conducted at "the maximum normal operating load...." However, "normal" is not defined in the proposed standard. In the absence of a definition, "normal" can mean almost anything to an owner/operator, or to a regulatory agency. To insure that tests are conducted under reasonably consistent operating conditions across the regulated boiler universe, EPA should define "normal" to mean "between 90% and 110% of the average operating rate during the preceding 12 months." Because some state agencies ordinarily require operating boilers at or near capacity, conducting full-load emission tests on boilers that normally operate at sub-capacity loading will be nonrepresentative of truly normal conditions on that boiler.

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-2525.1, Excerpt Number 12 to view the response.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 225

Comment: If Refinery Gas Will Be Regulated Separately From Other Gases In The Final Rule, EPA Should Include A Definition Of Refinery Gas. Units that use refinery gas as fuel are subject to different requirements under the proposed rule from units that fire "other gases" (Gas 2). If this situation remains in the final rule, refinery gas needs to be defined. We recommend the following definition, which we feel is most likely to reflect the fuels fired by the units identified as firing refinery gas in the rulemaking database.

Refinery gas means any gas which is generated at a petroleum refinery and which is combusted. Refinery gas includes natural gas when the natural gas is combined and combusted in any proportion with a gas generated at a refinery. Refinery gas includes gases generated from other facilities when that gas is combined and combusted in any proportion with gas generated at a refinery.

Including gases from contiguous and nearby facilities reflects the real situation at many refineries, where adjoining petrochemical operations, natural gas plants, terminal operations, third party hydrogen plants, electric utility plants, etc. have common fuel gas systems with a refinery. This is consistent with the definition of fuel gas in the Refinery 1 NESHAP (Part 63 Subpart CC). In that standard, refinery fuel gas and refinery fuel gas system are defined as follows.

Refinery fuel gas means a gaseous mixture of methane, light hydrocarbons, hydrogen, and other miscellaneous species (nitrogen, carbon dioxide, hydrogen sulfide, etc.) that is produced in the refining of crude oil and/or petrochemical processes and that is separated for use as a fuel in boilers and process heaters throughout the refinery.

Fuel gas system means the offsite and onsite piping and control system that gathers gaseous streams generated by refinery operations, may blend them with sources of gas, if available, and transports the blended gaseous fuel at suitable pressures for use as fuel in heaters, furnaces, boilers, incinerators, gas turbines, and other combustion devices located within or outside of the refinery. The fuel is piped directly to each individual combustion device, and the system typically operates at pressures over atmospheric. The gaseous streams can contain a mixture of methane, light hydrocarbons, hydrogen and other miscellaneous species.

The fact that this definition is meant to include gases from adjoining operations was made clear in the Final Background Information Document for Subpart CC [US EPA, Emission Standards Division, National Emission Standards for Hazardous Air Pollutants, Petroleum Refineries – Background Information for Final Standards, Summary of Public Comments and Responses, EPA453/R-95-015b, July 1995].

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-2960.1, Excerpt Number 6 to view the response.

Rule Language: Tables 1 through 10

Commenter Name: Renee Lesjak Bashel

Commenter Affiliation: Small Business Ombudsman and Small Business Environmental Assistance Programs
Document Control Number: EPA-HQ-OAR-2002-0058-2854.1
Comment Excerpt Number: 6

Comment: Recommendation: Clarify that Table 1, #9 refers to the definition "unit designed to burn gas 2
(other) category". It is not clear that gas 1 units are exempt from that Table, which we believe is the intent here.

Response: EPA has revised item 12 in Table 1 within the final rule to match the gas type as defined in 63.7575.

Commenter Name: Sharene Shealey
Commenter Affiliation: RRI Energy
Document Control Number: EPA-HQ-OAR-2002-0058-2759.1
Comment Excerpt Number: 12

Comment: Table 3 of the proposed rule refer to §§ 63.11202 and 63.11203. These sections are not included in subpart DDDDD.

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-3212.1, Excerpt Number 322 to view the response.

Commenter Name: Myra C. Reece
Commenter Affiliation: South Carolina Department of Health and Environmental Control
Document Control Number: EPA-HQ-OAR-2002-0058-2525.1
Comment Excerpt Number: 15

Comment: Table 10 to Subpart DDDDD of Part 63 states 63.7(b) applies, however, in 63.7545(d), if a subject facility is required to conduct a performance test, then a Notification of Intent to conduct a performance test must be submitted at least 30 days before the performance test is scheduled to begin. The EPA needs to provide clarification as to the amount of time given to subject facilities to report their Notification of Intent to conduct a performance test.

Response: EPA acknowledges the comment and has revised the notification to 60 days in 63.7545(d)

Commenter Name: Myra C. Reece

Commenter Affiliation: South Carolina Department of Health and Environmental Control
Document Control Number: EPA-HQ-OAR-2002-0058-2525.1
Comment Excerpt Number: 22

Comment: Tables 1 and 2 of the proposed rule should also state that the boiler or process heater must achieve "less than or equal to" the emission limit instead of "meet" for clarity.

Response: EPA has revised Tables 1 and 2 in the final rule to state "your emissions must not exceed the following limits…"

Commenter Name: Britt S. Fleming
Commenter Affiliation: Auto Group
Document Control Number: EPA-HQ-OAR-2002-0058-2775.1
Comment Excerpt Number: 68

Comment: Table 3 Work Practice Standards — This table contains an error. The Table establishes work practice standards for existing boilers < 10 mmBtufhr. While there are proposed work practice standards for existing boilers, new boilers < 10 nunBtu/hr are not mentioned. If new units are meant to be excluded from the work practices requirement, EPA must clarify this both in Table 3 and in § 633540.

Response: EPA has revised Table 3 within the final rule to include item 4 and state that no work practice standards apply to new small boilers that are not limited use boilers.

Commenter Name: Britt S. Fleming
Commenter Affiliation: Auto Group
Document Control Number: EPA-HQ-OAR-2002-0058-2775.1
Comment Excerpt Number: 69

Comment: Table 5 Performance Testing Requirements — There is no test method specified for D/F that should be used to comply with the proposed limits. .

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-2777.1, Excerpt Number 17 to view the response.

Commenter Name: Britt S. Fleming
Commenter Affiliation: Auto Group
Document Control Number: EPA-HQ-OAR-2002-0058-2775.1
Comment Excerpt Number: 70

Comment: Table 6 Fuel Analysis Requirements — There are several references to ASTM methods which must be purchased. If compliance requirements in the rule require reliance on ASTM documents, then EPA should make these documents publicly available either on EPA's website or in the docket for the rule.

Response: EPA cannot make these documents publicly available because they are protected by copyright laws.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 224

Comment: EPA has described energy assessments in the preamble as a Beyond-The-Floor option, meaning a control option more stringent than the MACT floor that could achieve greater emissions reductions. EPA has clearly written in the preamble that these energy assessments are considered to represent controls "beyond the MACT floor."
However, in Table 3 of the rule EPA lists energy assessments as a Work Practice Standard. The Clean Air Act describes Work Practices in §112(h) as an alternative to an emission standard when it is not feasible to prescribe or enforce an emission standard.
Because energy assessments are presented in this proposed rule as a standalone requirement for all facilities, rather than an alternative to meeting a proposed emission standard, the proposed energy assessments do not appear to meet the intent of §112(h) of the Clean Air Act as a Work Practice. EPA should resolve this inconsistency and remove energy assessments from Table 3.

Response: EPA acknowledges the comment but no changes, mentioned in this comment, have been made to Table 3 within the final rule. Please refer to the preamble for discussion of EPA's authority to require energy audit and energy audit requirement changes which are referred to as a beyond-the-floor standard.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 321

Comment: Table 2 of the proposed rule lists a dioxin/furan limit for biomass stoker boilers of 0.002 ng/dscm, while the preamble and the MACT floor memo indicate the proposed limit should be 0.004 ng/dscm.

Response: EPA has revised the limit within the final rule to be 0.005 ng/dscm, based on public other comments.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 322

Comment: In Table 3, the references to 63.11202 and 63.11203 are incorrect. We believe the correct reference may be 63.7540.

Response: EPA has updated the final rule and corrected reference errors.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 323

Comment: Table 5, item 5.d does not include the reference method for dioxin/furan. It should include reference method 23. EPA should also note which TEFs should be used to calculate the dioxin/furan TEQ values.

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-2777.1, Excerpt Number 17 to view the response.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 324

Comment: In Table 8 of the proposed MACT Rule at item 7, the Continuous Compliance Demonstration requirement cites 63.7530 (c) or (d) when it should be (b) or (c).

Response: EPA acknowledges the comment and has updated the final rule to correct typos and reference errors.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)

Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 325

Comment: Table 9 of the rule requires startup, shutdown, and malfunction reports if facilities have SSM events not consistent with the SSM plan and there were excess emissions. However, as EPA has proposed that the standards apply at all times with no SSM exemption and Table 10 states that the SSM provisions and plan requirements in the Part 63 General Provisions do not apply, the SSM reporting requirement in Table 9 should be removed.

Response: EPA has removed SSM requirements from Table 9 within the final rule. New language was included in the rule to address SSM events.

Commenter Name: Robert R. Scott
Commenter Affiliation: New Hampshire Department of Environmental Services, Air Resources Division
Document Control Number: EPA-HQ-OAR-2002-0058-2734.1
Comment Excerpt Number: 17

Comment: General Cross Reference Issues
In order to ensure correct interpretation of the regulation, NHDES is noting the following typographical errors that should be corrected prior to finalization of the proposed regulation. First, §63.11201 does not reference the Table 3 mercury standards but Table 3 references §63.11201. Second, the language preceding Table 2 refers to §§63.11202 and 63.11203 but should reference §63.11201. Finally, Table 3 refers to §63.11211(c) but should be §63.11211 (b).

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-3212.1, Excerpt Number 322 to view the response.

Commenter Name: Robert Karworski
Commenter Affiliation: Whirlpool Corporation
Document Control Number: EPA-HQ-OAR-2002-0058-2403.1
Comment Excerpt Number: 3

Comment: Clarification is requested on the Table 3 nomenclature. The table in places refers to “boilers” and in other places to “boilers & process heaters”. Does EPA intend to include both categories in these work standards?

Response: In Table 3, the work practices in items 1 and 2 apply to both boilers and process heaters; in item 3, they apply only to boilers.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 10

Comment: The applicability of the work practice requirements in the proposal is unclear because Table 3 in the proposed rule is unclear.

The heading in column 1 refers to boilers, but Items 1 and 2 in that column refer to boilers and process heaters, while the requirements in column 2 mention only boilers. The preamble discussion and related regulatory language seems to apply the tune-up requirement to both boilers and process heaters and the energy assessment requirement to facilities with boilers. However, the proposed definition of energy assessment in proposed 63.7575 refers to both boilers and process heaters.

Recommendation: Clarify the applicability of the tune-up requirement and the energy assessment requirement and revise Table 3 and the definition of "energy assessment" accordingly. Make all of the Table 3 language consistent.

Response: Both are applicable and EPA has revised Table 3 within the final rule to clarify this.

Commenter Name: Walter Tyler
Commenter Affiliation: Invista
Document Control Number: EPA-HQ-OAR-2002-0058-2761.1
Comment Excerpt Number: 13

Comment: Table 7 does not specify that dry scrubbers may be used to comply with the mercury emission limit. To address this, INVISTA recommends that mercury be added as a separate item in Table 7 and/or combined with Item 2 for hydrogen chloride.

Response: EPA has revised Table 7 within the final rule to include mercury in the dryscrubber operating parameters under item 2.b. in Table 7.

Commenter Name: Robert D. Morrison
Commenter Affiliation: Abbott Laboratories
Document Control Number: EPA-HQ-OAR-2002-0058-2764.1
Comment Excerpt Number: 23

Comment: The required method for measurement of D/F is not specified (missing) in Table 5 to Subpart DDDDD. Presumably the specified method would be USEPA Method 23. However, this represents a significant omission that compromises the regulated community's ability to review the proposed rule.

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-2777.1, Excerpt Number 17 to view the response.

Commenter Name: Chris Greissing
Commenter Affiliation: Industrial Minerals Association
Document Control Number: EPA-HQ-OAR-2002-0058-2740.2
Comment Excerpt Number: 32

Comment: 63.7520. What stack tests and procedures must I use
for performance tests?
(b) You must conduct each performance test according to the requirements in Table 5 to this subpart.

EPA needs to revise Table 5 to specified that EPA Reference Method 23 is the test method for dioxin/furan.

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-2777.1, Excerpt Number 17 to view the response.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-2702.1
Comment Excerpt Number: 103

Comment: Limits Should be Corrected.
The Proposed Rule includes CO emission limits for solid fuel burning units "corrected to 3 percent oxygen." 75 FR 32066-67. In the final rule, EPA should amend the CO limits so that they are corrected to 7 percent oxygen, just as the dioxin/furan limits are. This is appropriate as 7 percent oxygen is generally a more common operating level for units burning solid fuels. Furthermore, the Proposed Area Source Rule includes CO emission limits corrected to 7 percent oxygen. 75 FR 31932.

Response: EPA reconized the comment however, Table 1 and 2 limits for CO within the final rule are still at 3% oxygen for all fuels. EPA has retained the oxygen correction of 3 percent in the final rule for CO. Units with other oxygen corrections can adjust the measured value with a simple calculation.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-2702.1
Comment Excerpt Number: 104

Comment: The dioxin/furan emission limits for liquid and Gas 2 is currently corrected to 7 percent oxygen. 75 FR 32067. The dioxin/furan emission limit for liquid and Gas 2 should be corrected to 3 percent oxygen, just as oxygen is listed for CO for those fuels. This is appropriate as 3 percent oxygen is generally a more common operating level for liquid and gaseous fuels. Furthermore, the Proposed Area Source Rule includes dioxin/furan emission limits corrected to 3 percent oxygen. 75 FR 31932. Overall, CIBO recommends that EPA establish all emission corrections for a particular fuel corrected to the same oxygen level.

Response: EPA reconized the comment however, Table 1 and 2 limits for D/F within the final rule are still at 7% oxygen for all fuels. EPA has retained the oxygen correction of 7 percent in the final rule for dioxin/furans. This is consistent with how data was requested in the Phase II ICR survey, and units with other corrections can adjust the measured value with a simple calculation.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 180

Comment: Table 7 requires establishing separate operating parameter limits for pressure drop and liquid flow for wet scrubbers for HCl and for PM and Hg. Proposed 63.7530(c)(3)(i), on the other hand, requires that you establish one set of operating limits for these parameters using the maximum values from either the PM/Hg performance test or the Cl- performance test. Since you would have to meet the maximum values during operations, it makes no sense to establish two limits and Table 7 should be modified to match 63.7530(c)(1)(i).

Recommendation: Modify Table 7 wet scrubber requirements to match those in 63.7530(c)(1)(i)

Response: EPA acknowledges the comment but no change mentioned within this comment is needed for Table 7. The rule already specifies in 63.7530(b)(3)(i) that one set of operating parameters is needed for a wet scrubber that controls PM and HCl, and Table 7 references 63.7530(b) for settng the operating limits for both PM and HCl.

Commenter Name: Matthew Todd and David Friedman

Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 192

Comment: Proposed Table 6 specifies the methods to be used for fuel analysis. However, the Table only addresses coal and biomass. Reasonable procedures for gases and liquids are needed. For gas streams, fuel BTU content is typically determined using gas chromatography to identify the bulk of the constituents in the gas and then calculating the heat content from published component heat capacities. In some cases, sources even have on-line analyzers that continuously determine the heat content. These approaches to determining the heat content of gases should be specifically included in Table 6.

Recommendation: Revise Table 6 to include liquid and gas methodologies.

Response: The final rule provides for an "or equivalent" option for affected sources to obtain approval for additional methods. At this time, the Agency has finalized this approach in lieu of naming specific methods in the final rule.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 239

Comment: The header to Table 3 of the proposal references area source proposal paragraphs rather than the appropriate paragraphs in this proposal.

Recommendation: Correct the header to Table 3 to reference this rule.

Response: EPA has updated the final rule and corrected reference errors.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 240

Comment: Recommendation: Clarify the language in Table 3 to match the regulatory language and to be clear what work practice requirements apply to what equipment.

Response: EPA has revised Table 3 within the final rule.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 241

Comment: Table 9 Item 1.a calls for including in the compliance report Information required in 63.7550(c)(1) through (11). However, there are only 9 subparagraphs to 63.7550(c) so this reference needs to be corrected.

Recommendation: Correct the paragraph references in Table 9 Item 1.a.

Response: EPA has revised the reference to match the final rule [(c)(1) to (10)].

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 242

Comment: Table 9 Item 1.c states, relative to the compliance report, If you have a deviation from any emission limitation (emission limit and operating limit) or work practice standard during the reporting period, the report must contain the information in 63.7550(d). If there were periods during which the CMSs, including continuous emissions monitoring system, continuous opacity monitoring system, and operating parameter monitoring systems, were out-of-control, as specified in 63.8(c)(7), the report must contain the information in 63.7550(e). 63.7550(d) lists information required for a deviation where there is no CMS in use, while 63.7550(e) lists information required for a deviation where there is a CMS in use. CMS out-of-control periods are reportable under 63.8, but are not the only deviations that are reportable under 63.7550(e).

Recommendation: Revise Table 9 to match the requirements in 63.7550(d) and (e).

Response: EPA has revised Table 9 within the final rule to match the language in 63.7550(d) and (e). 1.c. was split into c. and d.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1

Comment Excerpt Number: 243

Comment: Tables 9 require sources to have SS&M plans and to report on their compliance with those plans and to file immediate reports if they did not follow their plans if there are excess emissions. Table 10 and the rule do not apply SS&M plan requirements, since the proposal applies all requirements during S&S periods and malfunctions are violations. Thus, SS&M plans serve no purpose and SS&M reporting requirements are covered by the normal deviation reporting. These requirements should be removed from Table 9. If, as we recommended earlier, certain startups and shutdowns are covered by a special work practice requirement that work practice, which might involve an S&S plan, would be the only time such a plan should apply and therefore is the only time such a plan is needed.

Recommendation: Delete the SS&M related requirements from Table 9 unless SS&M provisions are added to the final rule.

Response: EPA has removed SSM requirements from Table 9 within the final rule. New language was included in the rule to address SSM events.

Commenter Name: Leonard W. Sandridge
Commenter Affiliation: University of Virginia
Document Control Number: EPA-HQ-OAR-2002-0058-2769.1
Comment Excerpt Number: 27

Comment: Replace reference to §63.7530(c) with §63.7530(b) in Tables 4 and 7.

Response: EPA has updated the final rule to correct reference errors.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-2702.1
Comment Excerpt Number: 212

Comment: References to 63.110202 and 63.11203 are incorrect.
The Proposed Rule includes the following text associated with Table 3: "As stated in §§ 63.11202 and 63.11203, you must comply with the following applicable work practice standards:". 75 FR 32068 (emphasis added). EPA should clarify whether these section numbers are correct.

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-3212.1, Excerpt Number 322 to view the response.
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Commenter Name: Debra J. Jezouit
Commenter Affiliation: Class of '85 Regulatory Response Group
Document Control Number: EPA-HQ-OAR-2002-0058-2802.1
Comment Excerpt Number: 11

Comment: Proposed 63.7521(c) and (d) and Table 6 do not appear to address fuel sample collection for liquid fuels.

Response: Please see response to EPA-HQ-OAR-2002-0058-2960.1, excerpt 192 for methods included in Table 6.

Commenter Name: Richard Rosvold
Commenter Affiliation: Xcel Energy Services, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2955.1
Comment Excerpt Number: 19

Comment: §63.7521 and Table 6 go into great detail on fuel testing for solid fuels, but are silent on testing for liquid fuels. The EPA should revise this section to cover liquid fuels sampling procedures.

Response: Please see response to EPA-HQ-OAR-2002-0058-2960.1, excerpt 192 for methods included in Table 6.

Commenter Name: Richard Rosvold
Commenter Affiliation: Xcel Energy Services, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2955.1
Comment Excerpt Number: 9

Comment: At a minimum, Table 1 of the regulation should be edited to indicate the appropriate averaging time for each pollutant.

Response: EPA has revised Table 1 within the final rule to include the averaging times for those pollutants that are measured by a CMS (PM, CO/THC).

Commenter Name: Richard Rosvold
Commenter Affiliation: Xcel Energy Services, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2955.1
Comment Excerpt Number: 11

Comment: In Table 4, Item 5, EPA should clarify that "Any other control type" does NOT include "No add-on control."

Response: EPA has revised Item 5 within the final rule to read "Any other add-on air pollution control type …"

Commenter Name: David O'Keefe
Commenter Affiliation: USEC, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-3122
Comment Excerpt Number: 14

Comment: Table 3 — MACT floor for organic HAPs. Table 3 has more subcategories than Table 2. Table 2 has only 4 subcategories while Table 3 has 9. EPA should be consistent in unit subcategorization.

Response: EPA acknowledges the comment but no change is needed because work practices are determined by different criteria than the subcategories for numerical emission limits.

Commenter Name: David M. Kiser
Commenter Affiliation: International Paper Company
Document Control Number: EPA-HQ-OAR-2002-0058-2777.1
Comment Excerpt Number: 17

Comment: The proposed dioxin/furans limits are at or below the test method detection level (for some labs) and there is confusion in the language of proposed test methods – what can't be measured effectively can't be studied effectively as a practical matter.

EPA proposed dioxin/furan limits in the form of Toxic Equivalents (TEQ) but did not propose nor provide guidance on a standard TEQ methodology, thus determination of compliance or non-compliance with the proposed TEQ standard is not possible even apart from the sensitivity of test methodology and setting the standard near the detection level. TABLE 5 TO SUBPART DDDDD OF PART 63—PERFORMANCE TESTING REQUIREMENTS, 75 Fed. Reg. 32006, 32069-32070 (June 4, 2010), listed no method for determining the emission concentration of Dioxin/Furan as ng/dscfm (TEQ) corrected to 7% oxygen – the location in the table was a "blank".

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-2777.1, Excerpt Number 17 to view the response.

Commenter Name: Jim Eubank
Commenter Affiliation: Kentucky Division of Air Quality
Document Control Number: EPA-HQ-OAR-2002-0058-3176.2
Comment Excerpt Number: 19

Comment: Table 4 indicates "If you demonstrate compliance using...Wet scrubber control" and the like. These requirements appear to relate to continuous compliance demonstrations using parametric monitoring instead of compliance demonstrations such as performance testing.

Response: The commenter is correct. These are opreating limits that must be met at all times.

Commenter Name: David O'Keefe
Commenter Affiliation: USEC, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-3122
Comment Excerpt Number: 37

Comment: Table 5(d) dioxin/furans method. The Method number is blank, but likely refers to Method 23, Determination of Polychlorinated Dibenzo-p-dioxins and Polychlorinated Dibenzofurans from Municipal Waste Combustors. Method 23 appears to give two incorrect references in Sections 4.1.4 and 4.1.5. Section 4 of Method 5 is entitled, "Interferences" and is reserved. The correct references are as follows:
Method 23, Section 4.1.4 Leak-Check Procedure states, "Same as Method 5, Section 4.1.4." The leak-check procedures are found in Section 8.4 of Method 5.
Method 23, Section 4.1.5 Sampling Train Operation states, "Same as Method 5, Section 4.1.5." The sampling train operation requirements are found in Section 8.5 of Method 5.

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-2777.1, Excerpt Number 17 to view the response.

Commenter Name: David O'Keefe
Commenter Affiliation: USEC, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-3122
Comment Excerpt Number: 38

Comment: Table 8 opacity. The reference to § 63.7525 (b) probably should be (c).

Response: EPA acknowledges the comment and has updated the final rule to correct typos and reference errors.

Commenter Name: David O'Keefe
Commenter Affiliation: USEC, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-3122
Comment Excerpt Number: 39

Comment: Table 9 deviations. The reference to Table 8 appears to be incorrect and probably should be Table 3.

Response: EPA has updated the final rule to correct reference errors and the Table 8 reference was changed to Table 3.

Commenter Name: Christopher S. Colman
Commenter Affiliation: Hovensa LLC
Document Control Number: EPA-HQ-OAR-2002-0058-2863.1
Comment Excerpt Number: 45

Comment: Section §63.7515(f)and Section K, "How did we select the compliance requirements", of the preamble requires monthly fuel analysis to demonstrate compliance with fuel pollutant content limits; however the requirement is not included in Table 8, "Demonstrating Continuous Compliance". All continuous compliance requirements should be included in Table 8 of the rule.

Response: EPA acknowledges the comment but no change, mentioned in this comment, is made to Table 8. The requirements that would be added to Table 8 are already easily found in 63.7515 and 63.7540, so they do not need to be repeated or moved to Table 8.

Commenter Name: David M. Kiser
Commenter Affiliation: International Paper Company
Document Control Number: EPA-HQ-OAR-2002-0058-2777.1
Comment Excerpt Number: 51

Comment: The references in Table 4 of the proposed rule (for wet scrubber control) appear to be incorrect. All references in tables should be checked and corrected accordingly.

Response: EPA has updated the final rule to correct reference errors.

Commenter Name: David M. Kiser
Commenter Affiliation: International Paper Company
Document Control Number: EPA-HQ-OAR-2002-0058-2777.1
Comment Excerpt Number: 52

Comment: Table 4 in the proposed rule appears to have omitted the requirement to monitor pH as specified by section 63.7530(b)(3)(i).

Table 8 in the proposed rule should list the PM CEMS for a boiler with a heat input capacity of 250 MMBtu per hour or greater required to install a PM CEMS under section 63.7525(b). As previously stated, International Paper does not support the use of PM CEMS.

Response: EPA has revised Table 4 to include pH for wet scrubbers. The PM CEMS was not added to Table 8 because the requirements are spelled out completely in the rule text.

Commenter Name: David M. Kiser
Commenter Affiliation: International Paper Company
Document Control Number: EPA-HQ-OAR-2002-0058-2777.1
Comment Excerpt Number: 53

Comment: Table 8 in the proposed rule should list the CO CEMS for a boiler with a heat input capacity of 100 MMBtu per hour or greater required to install a CO CEMS under section 63.7525(a).

Response: EPA acknowledges the comment but no change, mentioned in this comment, is needed to Table 8. All of the continuous compliance requirements for CO CEMS are in 63.7525(a).

Commenter Name: David M. Kiser
Commenter Affiliation: International Paper Company
Document Control Number: EPA-HQ-OAR-2002-0058-2777.1
Comment Excerpt Number: 56

Comment: Table 3 of the proposed rule should clarify that the energy assessment is a “onetime” energy assessment. The word “one-time” should be inserted in Table 3, i.e., “You must meet the following ... Must have “a one-time” energy assessment performed on the major source facility by qualified personnel which includes”. The one-time assessment is mentioned in the preamble at 75 FR 32012 and 32026 but not in the rule. As previously stated, International Paper does not support the requirement for all major sources to conduct a one-time energy assessment.

Response: EPA has revised Table 3 within the final rule to indicate it is a one-time requirement.

Commenter Name: Lee B. Zeugin
Commenter Affiliation: Utility Air Regulatory Group

Document Control Number: EPA-HQ-OAR-2002-0058-2880.1
Comment Excerpt Number: 83

Comment: Proposed Tables 1 and 2 do not identify the different averaging periods for compliance with the PM limit at units with and without PM CEMS. 75 Fed. Reg. at 32,066-68.

Response: EPA has revised Tables 1 and 2 within the final rule to include the averaging periods (30 day rolling average for units with CEMS and 3-run average for others using a stack test.)

Commenter Name: Lee B. Zeugin
Commenter Affiliation: Utility Air Regulatory Group
Document Control Number: EPA-HQ-OAR-2002-0058-2880.1
Comment Excerpt Number: 84

Comment: The prefatory language to proposed Table 3 says "as stated in §§ 63.11202 and 63.11203." The referenced sections to not appear in this proposed subpart. 75 Fed. Reg. at 32,068.

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-3212.1, Excerpt Number 322 to view the response.

Commenter Name: Lee B. Zeugin
Commenter Affiliation: Utility Air Regulatory Group
Document Control Number: EPA-HQ-OAR-2002-0058-2880.1
Comment Excerpt Number: 85

Comment: Proposed Table 9 refers to a startup, shutdown, and malfunction plan that is not required elsewhere in the rule. 75 Fed. Reg. at 32,073.

Response: EPA has removed the SSM requirements from Table 9 within the final rule. New language was included in the rule to address SSM events.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 220

Comment: The Proposed Rule Includes an Ambiguous Classification of the Energy Assessment as Both a Beyond the Floor and Work Practice Standard. The proposed rule includes an ambiguous classification of an energy assessment as both a beyond-the-floor control technology and a work practice standard. This ambiguous classification needs to be resolved. In the proposed rule EPA states that "we believe that an energy assessment is an appropriate beyond-the-floor control technology because it is one of the measures identified in CAA section 112(d)(2)." Also in the proposed rule in Table 3 to Subpart DDDDD of Part 63, EPA proposes to require that an existing boiler must comply with the work practice standards in the table, of which an energy assessment is included.

EPA has described energy assessments in the preamble as a beyond-the-floor option, meaning a control option more stringent than the MACT floor that could achieve greater emissions reductions.

The Clean Air Act describes Work Practices in section 112(h) as an alternative to an emission standard when it is not feasible to prescribe or enforce an emission standard.

The proposed rule would require an energy assessment for all affected facilities, rather than as an alternative to meeting the proposed emission standards. As such, energy assessments do not meet the intent of Section 112(h) of the Clean Air Act as a Work Practice. EPA should resolve this inconsistency.

Response: EPA acknowledges the comment but no changes to Table 3, suggested by the commenter, have been made within the final rule. Please refer to the preamble for discussion of EPA's authority to require energy audit and energy audit requirement changes which are referred to as a beyond-the-floor standard.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 245

Comment: In Table 3, the references to section 63.11202 and section 63.11203 are incorrect. We believe the correct reference may be section 63.7540.

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-3212.1, Excerpt Number 322 to view the response.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 246

Comment: Table 5, item 5.d does not include the reference method for dioxin/furan. It should include reference Method 23.

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-2777.1, Excerpt Number 17 to view the response.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 247

Comment: In Table 8 of the proposed MACT Rule at item 7, the Continuous Compliance Demonstration requirement cites section 63.7530 (c) or (d) when it should be (b) or (c).

Response: EPA acknowledges the comment and has updated the final rule to correct typos and reference errors.

Rule Language Excluding Definitions and Tables 1-10

Commenter Name: George Woods
Commenter Affiliation: Littlejohn Engineering Associates
Document Control Number: EPA-HQ-OAR-2002-0058-1871
Comment Excerpt Number: 1

Comment: Under §63.7522, isn't the term Er in (Eq. 1) and (Eq. 2) incorrectly referenced? Shouldn't the Er term be described as it is for (Eq. 3) under the same paragraph?

Response: EPA has revised these terms for in equations 1, 2, 3, and 4 to be consistent and easier to read.

Commenter Name: Michael L. Steele
Commenter Affiliation: CraftMaster Manufacturing, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-1907.1
Comment Excerpt Number: 9

Comment: PM CEM's §63.7525(b)(4) and (6)
Why is a 30-day average required when compliance is based on 24-hour daily block average per §63.7S2S(b)(3)?

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-2777.1, Excerpt Number 44 to view the response.

Commenter Name: Michael L. Steele
Commenter Affiliation: CraftMaster Manufacturing, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-1907.1
Comment Excerpt Number: 30

Comment: Emissions Averaging

Equations 1 through 4 appear to have an error. The "+" sign should be a "divided by" sign.

Compliance should be based on the actual unit heat input per Equation 3 rather than the maximum heat input per Equation 1.

Continuous compliance, § 63.7S41(a)(1) says to use Equations 3 (or 4) and 5. What is the purpose of Equation 1?

Response: Divisions signs are already in the equations and were published. In Equations 1 and 2, the max rated heat input is used because these are for an initial compliance demonstration. In equations 3 and later, actual heat input is used because these are for ongoing compliance after data have been collected. Text around these equations has been revised to clarify the difference.

Commenter Name: Michael L. Steele
Commenter Affiliation: CraftMaster Manufacturing, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-1907.1
Comment Excerpt Number: 39

Comment: Recordkeeping § 63.7555
The proposed rules specify in paragraph (d)(3) to keep records of monthly hours of operation by each boiler or process heater. This applies to "limited use boilers and process heaters". Where is "limited use boilers and process heaters" defined? What provisions of the rules are not applicable to "limited use boilers and process heaters?"

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-2757.1, Excerpt Number 2 to view the response.

Commenter Name: Renee Lesjak Bashel
Commenter Affiliation: Small Business Ombudsman and Small Business Environmental Assistance Programs
Document Control Number: EPA-HQ-OAR-2002-0058-2854.1
Comment Excerpt Number: 2

Comment: Recommendation: Clarify that existing boilers <10 MMBTU/hr do not have to conduct emissions
tests.

Based on Table 2 in subpart DDDDD, emission limits only apply to units 10 MMBTU/hr or higher. Work practices in Table 3 apply to units below that level. The compliance demonstration language in s. 63.7505(c) states "…You must comply with all other applicable limits [emphasis added] using performance stack testing or the compliance monitoring system where applicable."

Language could be included in s. 63.7505(c) to indicate that where no emission limit applies, a unit must comply only with work practice standards and no emissions testing is required. Alternately, that paragraph could be more specific to "applicable limits listed in Table 2" to clarify where testing or CMS apply.

Response: EPA has revised 63.7505(c) to indicate that performance stack testing is needed only if subject to an applicable emission limit listed in Table 2.

Commenter Name: Myra H. Glover
Commenter Affiliation: Entergy Services, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2757.1
Comment Excerpt Number: 2

Comment: In addition, Entergy would like to request clarification on what appears to be an inconsistency within the proposed rule regarding limited-use boilers and process heaters. Proposed § 63.7555(d)(3) (recordkeeping) states that it applies to "limited-use boilers and process heaters," but EPA has not defined the term "limited-use boilers" and has not used that term elsewhere in the Proposed Rule. If it is necessary for EPA to state that § 63.7 555(d)(3) applies specifically to "limited-use boilers," then it stands to reason that EPA has created this subcategory of boilers -called "limited use" -to which the remainder of the Proposed Rule does not apply. EPA should clarify this point by establishing a definition of "limited-use boilers." As stated above, Entergy proposes that the definition include boilers with an operation of no more than 500 hours per year.

Response: Please refer to the preamble for discussion of the limited-use subcategory. EPA added provisions to exempt limited-use boilers from the emission limits, added hour/year monitoring and kept recordkeeping.

Commenter Name: Renee Lesjak Bashel
Commenter Affiliation: Small Business Ombudsman and Small Business Environmental Assistance Programs
Document Control Number: EPA-HQ-OAR-2002-0058-2854.1
Comment Excerpt Number: 7

Comment: Recommendation: Correct the following typos, where appropriate:
• 63.7540(a)(11) – it would make more sense if this paragraph were labeled (b), and the current (b) becomes (c)
• 63.7545(e) references "(1) through (9)", but the section ends at (7) –that should read "(1) through (7)"
• 63.7555(d)(6) and (d)(7) – (d) references "(1) through (5)", so wouldn't it make more sense if these were labeled (e) and (f), and the current (e) becomes (g)?

Response: EPA has corrected the 63.7540 reference from (a)(10) to (a)(11), in addition to correcting 63.7545(e) and 63.7555(d).

Commenter Name: Myra C. Reece
Commenter Affiliation: South Carolina Department of Health and Environmental Control
Document Control Number: EPA-HQ-OAR-2002-0058-2525.1
Comment Excerpt Number: 8

Comment: Clarify Deadline To Establish Emission Caps To Demonstrate Compliance With The Emission Averaging Option For The Emission Level Or Control Technology

In 63.7522(c), the emission rate achieved during the initial compliance test for the HAP associated with an existing boiler or process heater in the averaging group must not exceed the emission level that was being achieved on [THE DATE 30 DAYS AFTER PUBLICATION OF THE FINAL RULE IN THE FEDERAL REGISTER] or the control technology employed during the initial compliance test must not be less effective for the HAP being averaged than the control technology on [THE DATE 30 DAYS AFTER PUBLICATION OF THE FINAL RULE IN THE FEDERAL REGISTER]. However, it is proposed in 63.7522(g)(2)(i) that information associated with the applicable HAP emission level or the control technology installed as of [DATE 60 DAYS AFTER PUBLICATION OF THE FINAL RULE IN THE FEDERAL REGISTER] be included in the required emission's averaging plan. This appears to be a contradiction in dates and should be corrected in the final rule.

Response: EPA has updated 63.7522(c) in the final rule to be 60 days also.

Commenter Name: Myra C. Reece
Commenter Affiliation: South Carolina Department of Health and Environmental Control

Document Control Number: EPA-HQ-OAR-2002-0058-2525.1
Comment Excerpt Number: 9

Comment: Errors In Performance Tests Language

In 63.7522(j)(2), the EPA proposes 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)...." (75 FR 32055). There appears to be several grammatical errors in this clause: It is unclear as to how one can have "affected units from nonaffected units." Perhaps the intention of the EPA was to have included the conjunction "and" between the units described which would provide clarity. Also, the missing parenthesis at the end of the quoted clause suggests that relevant information may have been omitted.

Response: EPA has revised the language within the final rule as the commenter suggested.

Commenter Name: Myra C. Reece
Commenter Affiliation: South Carolina Department of Health and Environmental Control
Document Control Number: EPA-HQ-OAR-2002-0058-2525.1
Comment Excerpt Number: 10

Comment: Clarify Requirement To Submit An Implementation Plan For Emission Averaging Compliance Option

There is a contradiction in 63.7522(g)(1). This section mandates the submittal of an implementation plan by using the word "must." However, 63.7522(g) seems to indicate that submittal of the implementation plan is only necessary "upon request." This apparent discrepancy should be corrected in the final rule to avoid confusion.

Response: EPA has removed "upon request" from (g) within the final rule for clarification.

Commenter Name: Myra C. Reece
Commenter Affiliation: South Carolina Department of Health and Environmental Control
Document Control Number: EPA-HQ-OAR-2002-0058-2525.1
Comment Excerpt Number: 11

Comment: Correct Reference To Representative Operating Conditions In 63.7522(g)(2)(vii)

In 63.7520(c), performance tests must be conducted at the maximum normal operating load. However, 63.7522(g)(2)(vii) requires demonstration of compliance with each of the applicable emission limit(s) to be achieved under representative operating conditions. It appears the EPA used the original Boiler MACT language and did not replace it with maximum normal operating load which needs to be clearly defined in 63.7575.

Response: EPA has replaced maxium normal operating load within the rule to "representative operating conditions."

Commenter Name: Robin Mills Ridgway
Commenter Affiliation: Purdue University
Document Control Number: EPA-HQ-OAR-2002-0058-2782.1
Comment Excerpt Number: 11

Comment: Additionally, § 63.7540(a) does not appear to recognize the provisions set forth in § 63.7510 that exempt units that fire a single fuel from conducting fuel analyses during performance stack testing. Additional provisions should be included in this section to recognize the exemption from fuel analysis testing during performance stack testing in § 63.7510 for units that fire a single type of fuel.

Response: 63.7540(a) references other sections that contain the provision in question.

Commenter Name: Sharene Shealey
Commenter Affiliation: RRI Energy
Document Control Number: EPA-HQ-OAR-2002-0058-2759.1
Comment Excerpt Number: 13

Comment: The proposed § 63.7505(c) refers to § 63.7530(d) for fuel analysis calculations. Section 63.7505(c) should refer to § 63.7530(c).

§ 63.7505(c) You can demonstrate compliance with the applicable emission limit for HCl or mercury using fuel analysis if the emission rate calculated according to § 63.7530(d) is less than the applicable emission limit. Otherwise, you must demonstrate compliance for HCl or mercury using performance stack testing. You must demonstrate compliance with all other applicable limits using performance stack testing, or the continuous monitoring system (CMS) where applicable.

§ 63.7530(d) If you own or operate an existing unit with a heat input capacity of 10 million Btu per hour or less, you must submit a signed statement in the Notification of Compliance Status report that indicates that you conducted a tune-up of the unit.

Response: EPA has updated the final review to correct typos. The reference was corrected to 63.7530(c) because you can only use fuel analysis if the HCL or Hg input is less than the emission limit. Otherwise, you need to use add-on controls and use a stack test to demonstrate compliance.

Commenter Name: Myra C. Reece
Commenter Affiliation: South Carolina Department of Health and Environmental Control
Document Control Number: EPA-HQ-OAR-2002-0058-2525.1
Comment Excerpt Number: 13

Comment: Clarify Reduction In Performance Testing Frequency Based On Percentage Of The Emission Limit

In 63.7515(b), the EPA allows for less frequent performance testing if emissions are at or below 75 percent of the emission limit over three (3) consecutive years. However, 63.7550(c)(5) and 63.7555(d)(6) requires that annual reports and records, documenting that emissions in previous stack test(s) were less than 90 percent of the applicable emission limit, must be retained if a subject facility elects to test less frequently than annually. This appears to be a contradiction in setting the performance testing frequency threshold. Also, 63.7555(d) did not include paragraphs (d)(6) and (d)(7) in the citation for the section.

Response: EPA revised 63.7515(b) from 75 to 90 percent to be consistent with original intent. We also revised 63.7555(d) to include (d)(6) and (7).

Commenter Name: Myra C. Reece
Commenter Affiliation: South Carolina Department of Health and Environmental Control
Document Control Number: EPA-HQ-OAR-2002-0058-2525.1
Comment Excerpt Number: 14

Comment: Clarify Performance Test Notification Deadline

Section 63.7545(a) requires the 60 day Notification of Intent to conduct a performance test as prescribed in 63.7(b) but it fails to specify to whom it needs to be submitted. Perhaps the text could be revised to indicate that the Notification of Intent be submitted to the "delegated authority."

Response: EPA has added delegated authority to (a) within the final rule.

Commenter Name: Myra C. Reece
Commenter Affiliation: South Carolina Department of Health and Environmental Control
Document Control Number: EPA-HQ-OAR-2002-0058-2525.1
Comment Excerpt Number: 18

Comment: Errors In Tune-Up Requirement Language

The proposed reference to conduct annual performance tune-ups in 63.7515(e) is in error. Sources complying with tune-up requirements are not required to conduct performance tests. In 63.7540(a)(11), boilers or process heaters with a heat input capacity of less than 10 million Btu per hour have a biennial tune-up instead of an annual requirement.

Response: EPA has revised 63.7515(e) within the final rule to account for biennial tune-ups for small units.

Commenter Name: Steven M. Maruszewski
Commenter Affiliation: The Pennsylvania State University
Document Control Number: EPA-HQ-OAR-2002-0058-2729.1
Comment Excerpt Number: 20

Comment: Small Boilers – Initial Compliance Requirements- § 63.7510(c)
The rule does not set emissions limits for units below 10 MMBtu, instead requires a work practice standard of tune-ups to be followed. § 63.7510(c) states "If your boiler or process heater has a heat input capacity less than 100 MMBtu per hour your initial compliance demonstration for CO is conducting a performance stack test for CO according to Table 5 to this subpart. " This could be interpreted that all boilers, including those below 10 MMBtu would require an initial stack test. This is in
conflict with the Preamble discussion regarding the technological and economical challenges of testing small diameter stacks. It is suggested that the language be clarified by changing this section to state "If your boiler or process heater is subject to an emissions limit your initial compliance demonstration for CO is conducting a performance stack test..." This is similar language to the proposed Area Source MACT Rule.

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-2775.1, Excerpt Number 23 to view the response.

Commenter Name: Myra C. Reece
Commenter Affiliation: South Carolina Department of Health and Environmental Control
Document Control Number: EPA-HQ-OAR-2002-0058-2525.1
Comment Excerpt Number: 21

Comment: Clearly State Emission Limits To Be Achieved

In 63.7522(a), the proposed rule states that facilities may demonstrate compliance if the averaged emissions are "within" 90 percent of the applicable emission limit. The word "within" should be replaced with "less than" and the "=" symbol in all of the equations in this section should be replaced with "<".

Response: EPA has revised 63.7522(a) within the final rule to replace "within" with "not more than" so there is a 10% credit to the environment. Changing the = sign in the equations is not needed because they calculate the actual weighted average emissions for the averaged units. This value needs to be less than the limit for the pollutant for the fuel type and unit type.

Commenter Name: Britt S. Fleming
Commenter Affiliation: Auto Group
Document Control Number: EPA-HQ-OAR-2002-0058-2775.1
Comment Excerpt Number: 23

Comment: EPA Needs to Amend A Number of Rule Provisions to Reflect that Natural Gas Boilers and Process Heaters are Subject to Work Practices.

A number of the proposed initial compliance, monitoring, notification and recordkeeping requirements in the rule conflict with the requirements in § 63.7540 and Table 2 specifying that natural gas boilers and process heaters are subject to work practices and not emission limits. The following provisions need to be revised in the final rule to properly reflect the requirements for natural gas units:

(12) • Proposed § 63.7510, which addresses initial compliance requirements, is unclear in certain subsections with regard to whether the requirements only apply to units demonstrating compliance with emission limits. This provision should make it clear that the initial compliance demonstration requirements only apply where there is an emission limit applicable to a unit and that a unit subject to work practices is not required to demonstrate compliance. The wording in subsection (c) and (d), for example, is overly broad and could be interpreted to include units subject to work practice standards.

Response: EPA has revised 63.7510(a) through (d) within the final rule so they are not misinterpreted to include work practices.

Commenter Name: Britt S. Fleming
Commenter Affiliation: Auto Group
Document Control Number: EPA-HQ-OAR-2002-0058-2775.1
Comment Excerpt Number: 61

Comment: Proposed 63.7515 Subsection (g) – This provision appears to require submittal of all fuel analyses within 60 days after completion of a performance test. This should be clarified to identify that stack testing and the corresponding fuel analysis be submitted within 60 days. Compliance with other fuel analysis requirements can be included in the deviation reporting in the existing Title V program.

Response: For the fuel analysis, we have revised the language to require reporting of the stack tests results and the initial fuel analysis done at the time of the stack test, which are used to set the maximum Cl and Hg contents. The other subsequent monthly fuel analyses are reported with the semi-annual compliance report.

Commenter Name: Britt S. Fleming
Commenter Affiliation: Auto Group
Document Control Number: EPA-HQ-OAR-2002-0058-2775.1
Comment Excerpt Number: 64

Comment: Proposed § 63.7525(a)(6) – This provision addressing monitoring, installation, operation, and maintenance requirements needs to be clarified to identify that monitor downtime when performing maintenance does not constitute a deviation. This should reflect the allowance provided at § 63.7525(d)(2).

Response: EPA adapted language from (d)(2) to exclude faulty data from averages and to clarify what constitutes a deviation.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 310

Comment: Section 63.7515(e) states that facilities must conduct tune-ups according to 63.7520, but there are no tune-up requirements in the referenced section. We believe the correct reference is 63.7540.

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-2525.1, Excerpt Number 18 to view the response.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 311

Comment: Section 63.7525(f)(1) refers to “actual heat capacity” but we believe this should be “actual heat input” as the variable Hb is defined following Equation 3.

Response: We have revised this section to state "actual heat input" consistent with the request of the commenter and our initial intent.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 312

Comment: In 63.7525(a), Performance Specification 4A is required for CO CEMS. This performance specification was primarily developed for CEMS intended to demonstrate compliance with CO emission standards less than 200 ppmv. As the proposed rule includes CO limits for some units that are greater than 200 ppmv, EPA should also allow the use of Performance Specification 4, which was designed for CO span values in the 1000 ppmv range.

Response: EPA has added PS 4 to 63.7525(a), Performance Specification 4A.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 313

Comment: In the proposed rule at 40 CFR 63.7525(a), EPA specifies that a CO CEMS must be installed on all boilers and process heaters that are more than 100 MM Btu/hr. This language would require that a CO CEMS be installed on all existing and new Gas 1-fired units. However, EPA did not establish CO limits for these units, so it should not be necessary to install a CO CEMS. We recommend that EPA eliminate this confusion by re-writing the first sentence of 63.7525(a) to read: "If your boiler or process heater has a CO limitation and has a heat input of 100 MMBtu per hour or greater…."

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-2792.1, Excerpt Number 239 to view the response.
EPA has revised 63.7525(a) to clarify that only applies to units with CO limits.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 314

Comment: In the proposed rule at 40 CFR 63.7525(b), EPA specifies that a PM CEMS must be installed on all coal, biomass and residual oil boilers and process heaters that are more than 250 MM Btu/hr. The Agency also requires at 40 CFR 63.7525(c), EPA specifies that a continuous opacity monitoring system (COMS) must be installed on all boilers and process heaters that are have an opacity requirement. Table 4 to Subpart DDDDD of Part 63 requires that 10% opacity must be met by any unit using a dry electrostatic precipitator (ESP). Requiring these two monitors on units >250 MMBtu/hr and using an ESP is redundant since they are indicators of emissions of the same pollutant, particulate matter, and it makes no sense to require both on the same unit. We recommend that this redundancy be eliminated by requiring only one continuous monitor.

Response: EPA revised the rule to only require a COPMS on units that are not already otherwise required to install a PM CEMS.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 315

Comment: In the proposed rule at 40 CFR 63.7525(b), EPA specifies that a PM CEMS must be installed on all coal, biomass and residual oil boilers and process heaters that are more than 250 MM Btu/hr. The Agency also requires in section 2.a and 2.b of Table 4 to Subpart DDDDD of Part 63 that units using a fabric filter as a control install either a bag leak detection system or COMS. Again, it is redundant to require both a PM CEMS and COMS for large units. We recommend that this redundancy be eliminated by requiring only one continuous monitor.

Response: EPA revised the rule to only require a bag leak detector system on units that are not already otherwise required to install a PM CEMS. If a unit has a BLDS they do not install a COMS.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 316

Comment: We believe that 63.7525(i) that contains requirements for equipment used to measure sorbent injection rate incorrectly requires compliance with the requirements in paragraph (c), which contains requirements for COMS.

Response: EPA revised 63.7525(i) and corrected the reference from (c) to (d) in that section.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)

Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 317

Comment: Section 63.7530 (b) should reference Table 4 for establishing operating limits instead of Table 2, which contains emission limits.

Response: EPA has updated the final review to correct typos and reference errors.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 318

Comment: At 63.7530(b)(3), the reference should be (b)(3)(i) through (iv), not (c)(4)(i) thru (iv).

Response: EPA has updated the final review to correct typos and reference errors.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 319

Comment: 63.7530(b)(3)(ii) seems to require setting secondary voltage and current operating ranges for all ESP's, whether or not they are followed by additional wet control. This language is in conflict with Table 4 (Item 3) and Table 7 (Item 1.b). EPA should clarify the language in 63.7530(b)(3)(ii) to indicate that ESP parameter operating ranges should only be set if the ESP is followed by a wet control device.

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-3213.1, Excerpt Number 318 to view the response.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 320

Comment: In 63.7555(d)(3), there is a currently extraneous requirement to maintain records of monthly hours of operation for limited use boilers. As we recommend elsewhere in these comments, EPA should create a subcategory for limited use boilers, and then connect it to this recordkeeping requirement. Otherwise, this requirement should be removed as there are no requirements specifically for limited use boilers in the proposed rule.

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-2757.1, Excerpt Number 2 to view the response.

Commenter Name: Mike D. Craig
Commenter Affiliation: New Energy Corp.
Document Control Number: EPA-HQ-OAR-2002-0058-2695.1
Comment Excerpt Number: 5

Comment: Proposed 40 C.F.R. § 63.7530(b) refers to site specific operating limits in Table 2. NEC believes this reference should be to Table 4 since Table 2 has no operating limits.

Response: EPA has have updated the reference in the final rule.

Commenter Name: Mike D. Craig
Commenter Affiliation: New Energy Corp.
Document Control Number: EPA-HQ-OAR-2002-0058-2695.1
Comment Excerpt Number: 6

Comment: Proposed 40 C.F.R. § 63.7530(b) refers to paragraph (c)(4) and(c)(I) in two places which we believe should be (b)(3) and (b)(1), respectively.

Response: EPA has have updated the reference in the final rule.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 1

Comment: The phrase a major source of HAP as defined in 63.2 or 63.761 (40 CFR part 63, subpart HH, National Emission Standards for Hazardous Air Pollutants from Oil and Natural Gas Production Facilities) is unclear and should be revised. As proposed, this language would seem to say that a source which is major under either of the cited definitions is major for this rule. However, 63.761 is not an alternate to the 63.2 definition, as the proposed 63.7485 language indicates, but rather modifies it for certain oil and gas operations.

Recommendation: 63.7485 should be revised to read “a major source of HAP as defined in 63.2, except that for oil and gas facilities a major source of HAP as defined in 63.761 (40 CFR part 63, subpart HH, National Emission Standards for Hazardous Air Pollutants from Oil and Natural Gas Production Facilities),”

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-2857.1, Excerpt Number 2 to view the response.

Commenter Name: Mike D. Craig
Commenter Affiliation: New Energy Corp.
Document Control Number: EPA-HQ-OAR-2002-0058-2695.1
Comment Excerpt Number: 8

Comment: Proposed 40 C.F.R. § 63.7540(a)(4) references equation 5 of § 63.7530. There is no equation 5 in § 63.7530. NEC believes that EPA may be referring to equation 7.

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-2880.1, Excerpt Number 80 to view the response.

Commenter Name: Mike D. Craig
Commenter Affiliation: New Energy Corp.
Document Control Number: EPA-HQ-OAR-2002-0058-2695.1
Comment Excerpt Number: 9

Comment: Proposed 40 C.F.R. § 63.7545(d) states that notification to conduct a stack test must be submitted 30 days before the test is scheduled. Section 63.7(b) states that notification to conduct a stack test must be submitted 60 days before the test is scheduled, Table 10 indicates that general provision § 63.7(b) applies to subpart DDDDD. NEC would like clarification as to which provision applies.

Response: EPA updated the date to 60 days and added a comment that this needs to be confirmed.

Commenter Name: Mike D. Craig
Commenter Affiliation: New Energy Corp.
Document Control Number: EPA-HQ-OAR-2002-0058-2695.1
Comment Excerpt Number: 10

Comment: Proposed 40 C,F.R. § 63.7545(f) states that "If you operate a natural gas-fired boiler or process heater that is subject to this subpart... ." NEC questions whether a natural gas-fired boiler or process heater would be subject to this subpart, as the limits in Table 1 and 2 apply only to "other gases" which are defined as gaseous fuels other than natural gas,

Response: Natural gas fired units are part of the source category and affected source subject to this subpart but are not subject to any emission limits unless they fire other fuels that are subject to the emission limits. Please refer to the preamble for discussion of Gas 1 work practice standards.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 16

Comment: Under 63.7490(a)(2) another affected source is defined as each new or reconstructed industrial, commercial, or institutional boiler or process heater located at a major source as defined in 63.7575. In both the (a)(1) and (2) paragraphs the wording suggest that major source is defined in 63.7575, while it is actually the other terms in those paragraphs that are defined there. Major source is not defined in 63.7575.

Recommendation: Clarify 63.7490(a)(1) and (2) by moving the phrase "as defined in 63.7575" to a point earlier in the paragraph.

Response: EPA acknowledges the comment and has revised the final rule to avoid confusion with the definition of major source.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 19

Comment: We also request that the language of the proposed exemptions in 63.7491(i) be clarified, to make it clear that the exemption applies to not only a boiler or process heater that is specifically listed as an affected facility under CAA sections 112 or 129, but also to any boiler or process heater that is part of an affected facility under those CAA sections. For instance, under part 63 subpart UUU, a CO boiler is part of the Fluid Catalytic Cracking Unit affected facility and its stack emissions (including CO) are regulated by that subpart, but CO boilers are not specifically listed as an affected facility on their own under that rule.

Recommendation: Clarify the exclusion for boilers and process heaters regulated by other HAP regulations, by deleting the word “specifically” from 63.7491(i).

Recommendation: Maintain the proposed exemption for temporary boilers and expand that exemption to cover boilers and process heaters that operate less than 30 days per calendar year or that operate at less than 30% of their design capacity as an annual average.

Response: EPA has revised the language within the final rule to exclude units that are part of the affected source subject to another subpart of this part (i.e., another NESHAP under 40 CFR part 63). EPA did not expand the exemption for low-use boilers and heaters.

Commenter Name: Melvin E. Keener
Commenter Affiliation: Coalition for Responsible Waste Incineration (CRWI)
Document Control Number: EPA-HQ-OAR-2002-0058-2824.1
Comment Excerpt Number: 24

Comment: It appears the 10 percent discount factor discussed on page 32035 of the proposed rule should be in the denominator in Equations 1 — 4.

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-2702.1, Excerpt Number 208 to view the response.

Commenter Name: Leonard W. Sandridge
Commenter Affiliation: University of Virginia
Document Control Number: EPA-HQ-OAR-2002-0058-2769.1
Comment Excerpt Number: 26

Comment: Replace reference to Table 2 with Table 4 in §63.7530(b), first sentence.

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-3213.1, Excerpt Number 317 to view the response.

Commenter Name: Leonard W. Sandridge
Commenter Affiliation: University of Virginia
Document Control Number: EPA-HQ-OAR-2002-0058-2769.1
Comment Excerpt Number: 28

Comment: Replace reference to “(c)(4)(i) through (iv)” with “(b)(3)(i) through (iv)” in §63.7530(b)(3), first sentence.

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-3213.1, Excerpt Number 318 to view the response.

Commenter Name: Randall D. Quintrell
Commenter Affiliation: Georgia Paper and Forest Products Association, GPFPA
Document Control Number: EPA-HQ-OAR-2002-0058-2905
Comment Excerpt Number: 30

Comment: GP&FPA notes the following apparent errors in the Federal Register.
Under 63.7525 page 32055, middle column, (b)(1) should refer to 63.7540(a)(9) instead of (8).
Under 63.7540 page 32059, first column, (a)(6) should refer to equation 8 instead of equation 7.

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-2741.1, excerpt 72 and EPA-HQ-2002-0058-2880.1, excerpt 80 for the response.

Commenter Name: Donald R. Schregardus
Commenter Affiliation: Department of Defense
Document Control Number: EPA-HQ-OAR-2002-0058-2763.1
Comment Excerpt Number: 35

Comment: Some typographical, grammatical and cross-reference errors were identified in the proposed rule.

§63.7490(a)(1) states "The affected source of this subpart is the collection of all existing industrial, commercial, and institutional boilers and process heaters within a subcategory located at a major source as defined in §63.75 75.- This phrasing could lead to confusion since the term "major source" is not defined in §63.7575. Moving the phrase "located at a major source" could resolve the potential confusion and make it clear that the reference is to the subcategory definitions: "The affected source of this subpart is the collection of all existing industrial, commercial, and institutional boilers and process heaters located at a major source within a subcategory located at a major source as defined in §63.7575."

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-2960.1, Excerpt Number 16 to view the response.

Commenter Name: Donald R. Schregardus
Commenter Affiliation: Department of Defense
Document Control Number: EPA-HQ-OAR-2002-0058-2763.1
Comment Excerpt Number: 36

Comment: Some typographical, grammatical and cross-reference errors were identified in the proposed rule.

§63.7505(c) states "You can demonstrate compliance with the applicable emission limit for HCl or mercury using fuel analysis if the emission rate calculated according to §63.7530(d) is less than the applicable emission limit.- §63.7530(d) does not discuss calculating the HCL or mercury emission limit. This calculation reference should be §63.7521 and Table 6.

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-2759.1, Excerpt Number 13 to view the response.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 72

Comment: Requirements associated with the timing of the tune-up requirements are contained in 63.2515(e) as discussed below. This section is titled When must I conduct subsequent performance tests or fuel analyses? Along with the wording of paragraph (e), placing this information in this section suggests the tune-up is a performance test and thus subject to the notice and other requirements associated with performance tests. Making the tune-up work practice into a performance test is unreasonable, since there is no specific standard that the tune-up must attain. Furthermore, adding all the costs and burdens associated with a performance test was not included in the evaluations of this work practice or in the Information Collection Request. This information should be moved to another section of the rule or language added to make clear the tune-up is not a performance test.

Recommendation: Move the timing requirements for tune-ups out of the performance test section and make clear that tune-ups are not performance tests.

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-2525.1, Excerpt Number 18 to view the response.

Commenter Name: Matthew Todd and David Friedman

Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 74

Comment: Proposed 63.7540(a)(10) contains the specific tune-up work practice requirements for existing boilers and process heaters.

The proposed 63.7540(a)(10)(i)-(iii) reflect typical tune-up activities. Many jurisdictions require annual boiler inspections for safety reasons and boilers are often spared or can be shutdown when weather conditions are mild. Some jurisdictions require such inspections for process heaters particularly as part of a NOx minimization effort. However, not all boilers and few process heaters can be readily shut down. The proposed (a)(10)(i) and (ii) burner inspections could require such a shutdown, since burners are not always retractable and cannot always be inspected or cleaned with the process heater in service. In those cases where the boiler or process heater is not spared or cannot be shutdown without impacting steam or process heat consumers, this requirement should allow for delaying the burner inspection until the unit can be shut down without impact. Potential unit and process shutdowns were not considered in evaluating the tune-up emissions impacts, costs or burdens and are not justified.

Recommendation: Clarify that boiler and process heaters need not shut down to accomplish the required inspections or to clean burners.

Response: EPA acknowledges the comment but did not complete the recommended change because it would basically allow a source to not do the tune up indenfinitely.

Commenter Name: David A. Buff
Commenter Affiliation: Golder Associates Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2801.1
Comment Excerpt Number: 78

Comment: Extraneous requirement for monthly hours of operation for limited use boilers (there are no requirements specifically for limited use boilers in the proposed rule).

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-2757.1, Excerpt Number 2 to view the response.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1

Comment Excerpt Number: 84

Comment: Proposed 63.7515(e) starts out If you are required to meet an applicable work practice standard, you must conduct annual performance tune-ups... However, in addition to the tune-up work practice, there is an energy audit work practice, that will likely apply to all facilities. Thus, 63.7515(e) can be interpreted to override the biennial tune-up requirement for units <10 MMBTU/hr.

Recommendation: Revise the first sentence of 63.7515(e) to "If you are required to meet an applicablethe tune-up work practice standard, you must conduct annual performance tune-ups...

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-2525.1, Excerpt Number 18 to view the response.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 85

Comment: 63.7515(e) refers to 63.7520 for information on the tune-up, however, 63.7520 doesn't have any information on the tune-up. The information is in 63.7540

Recommendation: Correct the reference to 63.7520 in 63.7515(e).

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-2525.1, Excerpt Number 18 to view the response.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-2702.1
Comment Excerpt Number: 87

Comment: Additionally, § 63.7540(a) does not appear to recognize the provisions set forth in § 63.7510 that exempt units that fire a single fuel from conducting fuel analyses during performance stack testing. Additional provisions should be included in this section to recognize the exemption from fuel analysis testing during performance stack testing in § 63.7510 for units that fire a single type of fuel.

Clarification of Equation 7.

EPA requires that during performance testing for HCl, sources must determine "the fraction of the total heat input for each fuel type burned (Qi) based on the fuel mixture that has the highest content of chlorine, and the average chlorine concentration of each fuel type burned (Ci)." 75 FR 32057. The "maximum chlorine input level" must be determined using "Equation 7". 75 FR 32057. The definition given for Qi is unclear. EPA should clarify Equation 7 and the explanation given for Qi (i.e. "the fraction of total heat input from fuel type."). 75 FR 32057.

Response: EPA has added language to 63.7530(b) for clarification. If you switch fuels, you need to determine if you are increasing the Cl input. If it has increased, a performance stack test must be completed to determine compliance. Equation 7 was not revised because units that burn only a single fuel may do an analysis to show that they have not increased the Cl or Hg input and do not need to do a new stack test.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-2702.1
Comment Excerpt Number: 138

Comment: Monitoring
EPA Should Clarify CO CEMS are not Required for Gas 1 boilers >100 MMBtu/hr.
EPA should re-draft the proposed § 63.7525(a) so that it is applicable only if a unit has a CO limitation and a heat input of 100 MMBtu/hr or greater. Such clarification will ensure that unnecessary and costly requirements are not imposed on the Gas 1 subcategory or on Gas 2 units if numerical limits are not established.

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-2792.1, Excerpt Number 239 to view the response.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 164

Comment: Proposed 63.7510(c) requires CO performance testing boilers and process heaters with a heat input capacity of <100 MMBTU/hr even if no CO emission limit applies to that boiler or process heater. Without an applicable emission limit, there is no reason to performance test and testing such units certainly was not considered in the supporting record for this rulemaking.

63.7510(c) also requires a CO performance evaluation for the CO CEMS required by 63.7525(a) for all boilers and process heaters of ?100 MMBTU/hr, whether or not a CO emission limit applies. This requirement also must be changed to only apply to boilers and process heaters subject to a CO emission limit.

Recommendation: Revise 63.7510(c) to only apply to boilers and process heaters where a CO emission limit applies.

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-2775.1, Excerpt Number 23 to view the response.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 182

Comment: Proposed 63.7530(b) mistakenly references paragraph (c)(4) rather than (c)(3) and the introductory paragraph, 63.7530(c)(3), mistakenly references (c)(4) subparagraphs rather than (c)(3) subparagraphs.

Recommendation: Correct the cross-reference in 63.7530(b).

Response: EPA has revised the references in 63.7530(b). There is no reference in (c)(3) to another paragraph.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-2702.1
Comment Excerpt Number: 208

Comment: One technical amendment that should be made is that it appears the 10% discount factor discussed at 75 FR 32035 of the Proposed Rule should be in the denominator in Equations 1 – 4.

Response: EPA has revised the equations so that the factor was changed from 0.9 to 1.1 (the same as dividing by 0.9)

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-2702.1
Comment Excerpt Number: 211

Comment: Technical Errors
Reference should be (b)(3)(i)-(iv) – not (c)(4).
The proposed § 63.7530(b)(3) indicates that a source "must establish parameter operating limits according to paragraphs (c)(4)(i) through (iv) of this section." 75 FR 32057 (emphasis added). This should be changed in the final rule to reference (b)(3)(i) through (iv).

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-3212.1, Excerpt Number 318 to view the response.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 236

Comment: Proposed 63.7550(g) requires certain certifications. These requirements need clarification as follows. Also, note the (g) paragraphs should be numbered (1), (2) and (3), not (i), (ii) and (iii).

Proposed 63.7550(g)(i) requires a certification that This facility complies with the requirements in 63.7540(a)(10) to conduct an annual tune-up of the unit. However, most major sources will have many units subject to the tune-up requirement and this statement needs to be in the plural.

Proposed 63.7550(g)(ii) requires a certification that This facility has had an energy assessment performed according to 63.7530(e). However, the energy audit is a onetime requirement and, if it is finalized, this certification should be in the NCS and not have to be repeated in every compliance report.

Response: EPA moved the referenced paragraph and the three subparagraph to 63.7545(e)(8). 63.7550(g) was reserved.

Commenter Name: Robert P. Strieter
Commenter Affiliation: The Aluminum Association
Document Control Number: EPA-HQ-OAR-2002-0058-2711.1
Comment Excerpt Number: 6

Comment: The proposed rule requires the owner/operator to conduct a one-time Energy Assessment as a “beyond the MACT floor” control requirement. As described in the preamble and defined in the proposal rule, the scope of the Energy Assessment appears to go beyond the specific emission units regulated under the Boiler MACT by including the entire “major source facility” under this Energy Assessment. If this was EPA’s intent, the Aluminum Association opposes a requirement to conduct an energy assessment on facility operations which are not subject to the Boiler MACT rule. EPA needs to clarify that the Energy Assessment need only include the affect source(s) under Subpart DDDDD, which are the boilers and process heaters located at the facility.

Response: Please refer to the preamble for discussion of EPA's authority to require energy audit and energy audit requirement changes and discussion of the alternate output based standards and emission credits.

Commenter Name: John Hopewell
Commenter Affiliation: American Coatings Association
Document Control Number: EPA-HQ-OAR-2002-0058-2886.1
Comment Excerpt Number: 12

Comment: There are discrepancies in the monitoring discussion in the preamble versus the rule requirements that need to be addressed.

Response: EPA acknowledges the comment, and has updated the final rule to correct typos and reference errors.

Commenter Name: Debra J. Jezouit
Commenter Affiliation: Class of '85 Regulatory Response Group
Document Control Number: EPA-HQ-OAR-2002-0058-2802.1
Comment Excerpt Number: 16

Comment: Proposed 63.7555(d)(3) states that it applies to "limited-use boilers and process heaters" but EPA has not identified limited use sources as part of the Proposed Rule.

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-2757.1, Excerpt Number 2 to view the response.

Commenter Name: David Foerter
Commenter Affiliation: Institute of Clean Air Companies

Document Control Number: EPA-HQ-OAR-2002-0058-2937.1
Comment Excerpt Number: 28

Comment: The rule also proposes an approach for compliance requirements for various boiler and emission control technology configurations (75 FR 32014). Specifically, Section III.G.(4) states "For boilers and process heaters with dry scrubbers, we are proposing that you continuously monitor the sorbent injection rate and maintain the sorbent injection rate and maintain it at or above the operating limits established during the performance tests." Given there is no analogous section regarding dry injection systems, we presume this section was intended to cover these systems as well. Accordingly, we suggest this be clarified by adding "or dry injection systems" after "dry scrubbers" in this section.

Response: EPA added requirements for dry injection systems.

Commenter Name: Pamela F. Faggert
Commenter Affiliation: Dominion
Document Control Number: EPA-HQ-OAR-2002-0058-2908.1
Comment Excerpt Number: 37

Comment: Section 63.7515(e) appears to inappropriately reference 63.7520 (which addresses stack test requirements) rather than 63.7540 for tune-up requirements.

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-2525.1, Excerpt Number 18 to view the response.

Commenter Name: Chris M. Hobson
Commenter Affiliation: Southern Company
Document Control Number: EPA-HQ-OAR-2002-0058-2741.1
Comment Excerpt Number: 72

Comment: Section 63.7525(b) addresses the requirement to install PM CEMS. Section 63.7525(b)(1) states: "Each CEMS shall be installed, certified, operated and maintained according to the requirements in 63.7540(a)(8)." Section 63.7540(a)(8) is applicable to CO CEMS. The correct reference for PM CEMS should be Section 63.7540(a)(9).

Response: EPA acknowledges the comment and has updated the final rule to correct reference errors.

Commenter Name: Chris M. Hobson

Commenter Affiliation: Southern Company
Document Control Number: EPA-HQ-OAR-2002-0058-2741.1
Comment Excerpt Number: 74

Comment: Section 63.7540(a)(9)(i) states that a performance evaluation of a PM CEMS shall be conducted "according to the applicable requirements of 60.13 40 CFR, Performance Specification 11 in appendix B of 40 CFR part 60, and procedure 2 in appendix F of 40 CFR part 60." The reference to Procedure 2 should be removed from this section since Procedure 2 specifies the ongoing QA/QC requirements for PM CEMS after certification.

Response: EPA has updated teh final rule based on the change recommended. Procedure 2 is specified in (a)(9)(iii) for the quarterly accuracy determinations.

Commenter Name: Russ A. Wozniak
Commenter Affiliation: Dow Chemical Company
Document Control Number: EPA-HQ-OAR-2002-0058-2632.1
Comment Excerpt Number: 89

Comment: Incorrect Reference in 63.7505(c) - The reference to Section 63.7530(d) should be to 63.7530(c).

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-2759.1, Excerpt Number 13 to view the response.

Commenter Name: Russ A. Wozniak
Commenter Affiliation: Dow Chemical Company
Document Control Number: EPA-HQ-OAR-2002-0058-2632.1
Comment Excerpt Number: 90

Comment: Incorrect Reference in 63.7525(b)(1) - The reference to Section 63.7540(a)(8) should be to 63.7540(a)(9).

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-2741.1, Excerpt Number 72 to view the response.

Commenter Name: John Steber
Commenter Affiliation: Performance Fibers
Document Control Number: EPA-HQ-OAR-2002-0058-3174

Comment Excerpt Number: 4

Comment: The wording of the subcategories of boilers and process heaters identified under section 63.7499 and their respective definitions under section 63.7575 are not consistent. For example, section 63.7499(a)(9) reads "Units designed to burn natural gas/refinery gas" and its proposed definition reads "Unit designed to burn gas 1 (NG/RG)", as stated at the beginning of this section. PFI recommends that the wording in one or both sections be revised as necessary for consistency.

Response: EPA acknowledges the comment and has updated the final rule to correct typos and reference errors.

Commenter Name: Chris Welch
Commenter Affiliation: Colorado Springs Utilities
Document Control Number: EPA-HQ-OAR-2002-0058-2943.1
Comment Excerpt Number: 6

Comment: Within the proposed rule, IV. Summary of This Proposed Rule, D. What are the proposed MACT and GACT standards, the following statement is made,"If your boiler bums oil, or oil in combination with a gaseous fuel, the unit is in the oil subcategory, except if the unit burns oil only during periods of gas curtailment."

Gas curtailment needs to be clearly defined in the rule, and in CSU's current tariff with our interstate transport supplier, we reference curtailment pursuant to the Natural Gas Policy Act of 1978.

Response: EPA acknowledges the comment and has updated the final rule to correct typos and reference errors. We have adjusted the definition of curtailment in the final rule. This standard does not employ GACT standards, which are covered under the area source rule.

Commenter Name: Jim Eubank
Commenter Affiliation: Kentucky Division of Air Quality
Document Control Number: EPA-HQ-OAR-2002-0058-3176.2
Comment Excerpt Number: 9

Comment: 40 CFR 63.7505 is entitled "What are my general requirements for complying with this subpart?" 40 CFR 63.7505(c) begins with compliance demonstrations for HCl or mercury. The last sentence in that paragraph states that "You must demonstrate compliance with all other applicable limits using performance stack testing, or the continuous monitoring system (CMS) where applicable." It is likely that this sentence is intended as a general statement covering all of the compliance demonstration options, but as written, it is more confusing than helpful, for the following reasons:

This sentence could be easily missed by someone not interested in HCl or mercury compliance demonstration methods and therefore should either be a separate paragraph or be used at the beginning of the sentence with HCl or mercury compliance listed as an exception to the more general requirement.

The sentence is confusing because it could be interpreted that there is an option between performance stack testing or CMS. This is inconsistent with 40 CFR 63.7530(a) which states that “you must demonstrate initial compliance with each emission limit that applies to you by conducting initial performance tests (performance stack tests and fuel analyses) and establishing operating limits...,” i.e. there is no mention in the latter that demonstrating compliance with emission limits by CMS is permissible, but rather that operating limits will be established.

It appears that compliance maybe demonstrated by CEMS (PM or CO1), but not by parametric monitoring. The Division suggests that the use of the general term "CMS" be avoided when only the specific (CEMS) is allowed. Although doubtful this is the intent, if parametric monitoring is permitted without stack testing to establish correlations between operational parameters and compliance with emission limitations, the Division disagrees that it should be allowed and therefore the regulation should be very clear that is not the case. Furthermore, use of parametric monitoring is useful as a substitute for direct monitoring of emissions for continuous monitoring purposes, but is not adequate for compliance demonstrations with emission limits.

[Footnote 1: See 40 CFR 63.7510(c) and (d). Note that these paragraphs are not consistent with 40 CFR 63.753(a).]

Response: We have revised 63.7505(c) and (d). We changed the order in (c) so that the first sentence refers to CEMS and COMS. We revised (d) to clarify that a CPMS is only used to comply with an operating limit after a performance stack test.

Commenter Name: Jim Eubank
Commenter Affiliation: Kentucky Division of Air Quality
Document Control Number: EPA-HQ-OAR-2002-0058-3176.2
Comment Excerpt Number: 13

Comment: 40 CFR 63.7505(c) contains an error, the reference to 40 CFR 63.7530(d) should be changed to 40 CFR 63.7530(c).

Response: EPA acknowledges the comment and has updated the final rule to correct typos and reference errors.

Commenter Name: Jim Eubank

Commenter Affiliation: Kentucky Division of Air Quality
Document Control Number: EPA-HQ-OAR-2002-0058-3176.2
Comment Excerpt Number: 14

Comment: 40 CFR 63.7530, which is entitled, “How do I demonstrate initial compliance with the emission limits and work practice standards.” Also is related to initial compliance. It appears that 40 CFR 63.7510 is intended to cover initial compliance after the regulation is newly promulgated while 40 CFR 63.7530 is intended to cover initial compliance thereafter. However, the two are inconsistent and it is not clear why. For example, as noted above, 40 CFR 63.7530 does not appear to permit compliance demonstration by CEMS and COMS, whereas 40 CFR 63.7510(c) and (d) do permit initial compliance by CO and PM CEMS. The Division suggests that these two sections be merged to ensure consistency, and where divergence is intended, it would be clearer if the different requirement was explicitly identified as such.

Response: We revised 63.7530(a) to add: "If applicable, you must also install, and operate, maintain all applicable CMS (including CEMS, COMS, and continuous parameter monitoring systems) according to §63.7525. Although there is some overlap in these two sections, the revised language does add clarity to this concern.

Commenter Name: Jim Eubank
Commenter Affiliation: Kentucky Division of Air Quality
Document Control Number: EPA-HQ-OAR-2002-0058-3176.2
Comment Excerpt Number: 15

Comment: 40 CFR 63.7510(a) states that “(f) or affected sources that elect to demonstrate compliance requirement by stack testing....” The word "elect" should be deleted. The requirements should apply whether the source elects to demonstrate compliance by stack testing, or is required to demonstrate compliance by stack testing.

Response: EPA acknowledges the comment and has updated the final rule to correct typos and reference errors.

Commenter Name: David O'Keefe
Commenter Affiliation: USEC, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-3122
Comment Excerpt Number: 31

Comment: Reference in § 63.7515(e). The reference to work standards in § 63.7520 appear to be incorrect. The referenced § 63.7520 is for performance testing.

Response: EPA acknowledges the comment and has updated the final rule to correct typos and reference errors.

Commenter Name: David O'Keefe
Commenter Affiliation: USEC, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-3122
Comment Excerpt Number: 34

Comment: Equations in § 63.7540. There appears to be an incorrect equation reference in number (4) of this section. Number 4 discusses using Equation 5 of § 63.7530 for maximum chlorine input. There is no Equation 5 in this section, and it appears that the reference should be to Equation 7.

There appears to be an incorrect equation reference in number (6) of this section. Number 6 discusses using Equation 7 of § 63.7530 for maximum mercury input. The reference should be to Equation 8.

Response: EPA acknowledges the comment and has updated the final rule to correct typos and reference errors.

Commenter Name: David O'Keefe
Commenter Affiliation: USEC, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-3122
Comment Excerpt Number: 35

Comment: Equations in § 63.7555. The references to Equations 5 and 9 appear to be incorrect and should reference Equations 7 and 10, respectively.

Response: EPA acknowledges the comment and has updated the final rule to correct typos and reference errors.

Commenter Name: David M. Kiser
Commenter Affiliation: International Paper Company
Document Control Number: EPA-HQ-OAR-2002-0058-2777.1
Comment Excerpt Number: 54

Comment: EPA should make the following clarifications to the proposed rule:

40 CFR 63.7525(a) should be modified to exclude natural gas fired boilers from having to install a CO monitor. There are no emission standards listed in Tables 1 or 2 of the proposed rule for

new or existing natural gas fired boilers and process heaters. Suggested language is provided below.

Response: EPA has revised 63.7525(a) within the final rule so that it only applies to units subject to a CO limit.

Commenter Name: David M. Kiser
Commenter Affiliation: International Paper Company
Document Control Number: EPA-HQ-OAR-2002-0058-2777.1
Comment Excerpt Number: 55

Comment: From: "If your boiler or process heater has a heat input capacity of 100 MMBtu per hour or greater, you must install....a ...CEMS for CO..."

To: "If your boiler or process heater has a heat input capacity of 100 MMBtu per hour or greater (excluding units designed to burn natural gas/refinery gas), you must install....a ...CEMS for CO..."

Response: EPA has revised 63.7510 (c) and (d) within the final rule to speicfy that they apply to units subject to CO and PM limits, respectively.

Commenter Name: Lee B. Zeugin
Commenter Affiliation: Utility Air Regulatory Group
Document Control Number: EPA-HQ-OAR-2002-0058-2880.1
Comment Excerpt Number: 76

Comment: Proposed § 63.7530(b) contains incorrect references for all the proposed requirements. Specifically, it states that units demonstrating compliance through performance stack testing must "establish each site-specific operating limit in Table 2 . . . that applies . . . according to the requirements in § 63.7520, Table 7 . . ., and paragraph (c)(4) or this section." 75 Fed. Reg. at 32,056. However, proposed Table 2 sets out emission limits for existing boilers and process heaters, not "site-specific operating limits." Operating limits are in proposed Table 4. Paragraph (c)(4) addresses Hg emission rates from fuel analysis. Paragraph (b)(3) addresses parameter operating. Proposed § 63.7530(b) also states that all such units must conduct fuel analysis and "establish maximum fuel pollutant input levels according to paragraphs (c)(1) through (3). . ." 75 Fed. Reg. at 32,057. Paragraphs (c)(1) through (3) address units that demonstrate compliance through fuel analysis, not through performance testing. Paragraphs (b)(1) through (3) appear to be the procedures for establishing maximum fuel pollutant input levels.

Response: EPA has updated the final review to correct reference errors and the references in 63.7530(b) have been corrected.

Commenter Name: Deb Hastings
Commenter Affiliation: Texas Oil and Gas Association
Document Control Number: EPA-HQ-OAR-2002-0058-2857.1
Comment Excerpt Number: 2

Comment: §63.7485 should be revised to read "a major source of hazardous air pollutants (HAP) as defined in §63.2, except that for oil and gas facilities a major source of HAP as defined in §63.761 (40 CFR part 63, subpart 1111, National Emission Standards for Hazardous Air Pollutants from Oil and Natural Gas Production Facilities)"

Per proposed §63.7485, this regulation applies to an "industrial, commercial, or institutional boiler or process heater as defined in §63.7575 that is located at, or is part of, a major source of HAP as defined in §63.2 or §63.761 (40 CFR part 63, subpart IfEl, National Emission Standards for Hazardous Air Pollutants from Oil and Natural Gas Production Facilities), except as specified in §63.7491." This phrase is unclear and should be revised. As proposed by the U.S. Environmental Protection Agency (EPA), this language would seem to say that a source which is major under either of the cited defmitions is major for this rule. However, §63.761 is not an alternate to the §63.2 definition, as the proposed §63.7485 language indicates, but rather modifies it for certain oil and gas operations.

Response: EPA acknowledges the comment and has revised the section within the final rule to avoid the ambiguity.

Commenter Name: Jim Eubank
Commenter Affiliation: Kentucky Division of Air Quality
Document Control Number: EPA-HQ-OAR-2002-0058-3176.2
Comment Excerpt Number: 10

Comment: 40 CFR 63.7505(c) and (d) do not belong under general requirements, but rather should be listed under sections relating to emission and operating limit compliance demonstrations, of which there are at least two: 40 CFR 63.7510 which is entitled “What are my initial compliance requirements and by what date must I conduct them” and 40 CFR 63.7530 which is entitled “How do I demonstrate initial compliance with the emission limits and work practice standards.”

Response: EPA acknowledges the comment but no change was made. It is not clear that this text should be moved to the later rule sections. 63.7505(c) and (d) are still general in nature.

Commenter Name: Jim Eubank
Commenter Affiliation: Kentucky Division of Air Quality
Document Control Number: EPA-HQ-OAR-2002-0058-3176.2
Comment Excerpt Number: 11

Comment: Because 40 CFR 63.7505(d)(1) (rules for site-specific monitoring) is listed as subordinate to 40 CFR 63.7505(d) (requirement to develop site-specific monitoring if compliance is demonstrated via performance stack testing), it could be interpreted to mean that 40 CFR 63.7505(d)(1) only applies if 40 CFR 63.7505(d) applies. However, it appears that 40 CFR 63.7505(d)(1) should apply to all CMS, or at least, all parametric monitoring, since much, if not all, the requirements are duplicative of regulations governing CEMS and COMS. The Division suggests that 40 CFR 63.7505(d)(1)-(4) be moved to sections pertaining to monitoring, such as 40 CFR 63.7535 or 40 CFR 63.7540, or at least elevated so that it is not subordinate to 40 CFR 63.7505(d) (i.e., 40 CFR 63.7505(e)).

Response: We modified section 63.7505(d) to encompass all types of CMS (CEMS, COMS, and CPMS) to clarify the applicability requirements of (d)(1) through (d)(4).

Commenter Name: Michael L. Corvese
Commenter Affiliation: Thermo Fisher Scientific, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2997.1
Comment Excerpt Number: 13

Comment: Recommend that EPA remove the requirement at section 63.7525(i)(j)(6) that the BLD should activate an audible alarm.

The referenced section states:

(6) The bag leak detection system must be equipped with an alarm system that will sound automatically when an increase in relative particulate matter emissions over a preset level is detected. The alarm must be located where it is easily heard by plant operating personnel.

Many boiler control rooms are equipped with visual alarms that the operator must acknowledge and respond to. The type of alarm that is used must be at the discretion of the plant, may be affected by safety or plant operational priorities, and should not be specified by EPA.

Response: EPA has revised 63.7525(i)(j)(6) to allow either audible or visual alarms.

Commenter Name: Paul N. Cicio
Commenter Affiliation: Industrial Energy Consumers of America
Document Control Number: EPA-HQ-OAR-2002-0058-2752.1
Comment Excerpt Number: 18

Comment: § 63.7540(a) does not appear to recognize the provisions set forth in § 63.7510 that exempt units that fire a single fuel from conducting fuel analyses during performance stack testing. Additional provisions should be included in this section to recognize the exemption in § 63.7510 for units that fire a single type of fuel from fuel analysis testing during performance stack testing.

Response: EPA has added language to 63.7530(b) for clarification. If you switch fuels, you need to determine if you are increasing the Cl input. If it has increased, a performance stack test must be completed to determine compliance. Equation 7 was not revised because units that burn only a single fuel may do an analysis to show that they have not increased the Cl or Hg input and do not need to do a new stack test.

Commenter Name: Jim Eubank
Commenter Affiliation: Kentucky Division of Air Quality
Document Control Number: EPA-HQ-OAR-2002-0058-3176.2
Comment Excerpt Number: 18

Comment: 40 CFR 63.7515 is entitled "When must I conduct subsequent performance tests or fuel analyses." As the title suggests, this section pertains to when tests are performed, as opposed to what subsequent compliance demonstrations are required. Other sections related to compliance demonstrations specify "initial". The Division recommends that the regulation explicitly state what subsequent compliance demonstrations are required. In the alternative, no distinction should be made between initial and subsequent compliance determinations generally and where distinctions are made, they be explicitly identified.

Response: EPA has revised the langage slightly in different parts of the rule to clarify whether a procedure was for the initial or all compliance demonstrations. However, the rule is already reasonably clear on what needs to be done and when to do it.

Commenter Name: Richard Rosvold
Commenter Affiliation: Xcel Energy Services, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2955.1
Comment Excerpt Number: 21

Comment: §63.7540(a)(6) discusses compliance with mercury limits through compliance testing. This paragraph refers to Equation 7 in §63.7530, which is concerned with chlorine input and HCI limits, not mercury limits. These citations need to be corrected.

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-2880.1, Excerpt Number 80 to view the response.

Commenter Name: Michael Hutcheson
Commenter Affiliation: Ameren Services
Document Control Number: EPA-HQ-OAR-2002-0058-2803.1
Comment Excerpt Number: 34

Comment: 63.7545(e) contains a referencial error.
The last sentence of this paragraph refers to paragraphs (e)(1) through (9) of this section, however, there are only seven (7) subparagraphs under paragraph (e).

Response: EPA aknowledges the comment and has updated the final review to correct typos and reference errors.

Commenter Name: Michael Hutcheson
Commenter Affiliation: Ameren Services
Document Control Number: EPA-HQ-OAR-2002-0058-2803.1
Comment Excerpt Number: 36

Comment: The US EPA makes a clear error in paragraph (e)(5) where it references a “90 % emission limit threshold required in 63.7515(b) or (c)” when those reference paragraphs clearly refer to a 75 % threshold.

Response: EPA has updated the final review to correct reference errors and the mentioned references have been changed to 63.7515(b) and (c) in 63.7555(d)(6).

Commenter Name: David M. Kiser
Commenter Affiliation: International Paper Company
Document Control Number: EPA-HQ-OAR-2002-0058-2777.1
Comment Excerpt Number: 42

Comment: EPA should correct the following errors in the proposed rule:

The operating limits for parameter monitoring systems (scrubber effluent pH, liquid flow rate, pressure drop, etc.) should be based on the 4-hour run performance test required by section 63.7520(d). Specifically, section 63.7525(d)(4) should be modified from “determined the 3-hour block average” to “determined the 4- hour block average”. This is also specified in the preamble (75 FR 32033, 3rd paragraph) which states,” ...You would be required to set parameters based on 4-hour block averages during the compliance test, and demonstrate continuous compliance by monitoring 12-hour block average values for most parameters. We selected this averaging period to reflect operating conditions during the performance test to ensure the control system is continuously operating at the same or better level as during a performance test demonstrating compliance with the emission limits”.

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-2777.1, Excerpt Number 44 to view the response.
EPA has revised 3-hour averages to 4-hour averages within the final rule.

Commenter Name: David M. Kiser
Commenter Affiliation: International Paper Company
Document Control Number: EPA-HQ-OAR-2002-0058-2777.1
Comment Excerpt Number: 44

Comment: 40 CFR 63.7525(d)(4) appears to incorrectly refer to (c)(3) rather than (d)(3).

Response: EPA has revised 63.7525(b)(3) within the final rule to be a 30-day rolling average.

Commenter Name: Christopher S. Colman
Commenter Affiliation: Hovensa LLC
Document Control Number: EPA-HQ-OAR-2002-0058-2863.1
Comment Excerpt Number: 44

Comment: Proposed Rule Language §63.7515(f):
”.... you must conduct monthly fuel analysis according to §63.7521 for each type of fuel burned...”

Comments:
Since emission limits do not apply to all types of fuel, the requirement under § 63.7515(f) should read “.... you must conduct monthly fuel analysis according to §63.7521 for each type of fuel burned to which an emission limit applies...”

Response: EPA has updated the final rule to reflect the suggested change.

Commenter Name: David M. Kiser
Commenter Affiliation: International Paper Company
Document Control Number: EPA-HQ-OAR-2002-0058-2777.1
Comment Excerpt Number: 45

Comment: In Equation 10, the reference to the 90th percentile confidence level concentration of chlorine should be expressed as Ci90 not C90i.

Response: EPA has corrected this typo within in Equation 10 and other equations. A comment was added to Equation 10 in the file.

Commenter Name: David M. Kiser
Commenter Affiliation: International Paper Company
Document Control Number: EPA-HQ-OAR-2002-0058-2777.1
Comment Excerpt Number: 46

Comment: Following Equation 10, in the definition of Ci90, it appears Equation 8 is incorrectly referenced rather than Equation 9. Equation 8 refers to Mercuryinput.

Response: EPA has updated the final rule to correct typos and reference errors.

Commenter Name: David M. Kiser
Commenter Affiliation: International Paper Company
Document Control Number: EPA-HQ-OAR-2002-0058-2777.1
Comment Excerpt Number: 47

Comment: Following Equation 11, in the definition of HGi90, it appears Equation 8 is incorrectly referenced rather than Equation 9. Equation 8 refers to Mercuryinput.

Response: EPA has updated the final rule to correct typos and reference errors. This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-2777.1, Excerpt Number 46 to view the response.

Commenter Name: David M. Kiser
Commenter Affiliation: International Paper Company
Document Control Number: EPA-HQ-OAR-2002-0058-2777.1
Comment Excerpt Number: 48

Comment: 40 CFR 63.7540 appears to incorrectly refer to several equations. This section should be checked and corrected accordingly.

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-2880.1, Excerpt Number 80 to view the response.

Commenter Name: David M. Kiser
Commenter Affiliation: International Paper Company
Document Control Number: EPA-HQ-OAR-2002-0058-2777.1
Comment Excerpt Number: 49

Comment: 40 CFR 63.7540(a)(4) and (6) appears to incorrectly refer to section 63.7530(c) rather than section 63.7530(b).

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-2880.1, Excerpt Number 80 to view the response.

Commenter Name: David M. Kiser
Commenter Affiliation: International Paper Company
Document Control Number: EPA-HQ-OAR-2002-0058-2777.1
Comment Excerpt Number: 50

Comment: 40 CFR 63.7555(d)(3) refers to limited-use boilers which appears to be a carryover from the September 13, 2004 vacated rule.

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-2757.1, Excerpt Number 2 to view the response.

Commenter Name: Lee B. Zeugin
Commenter Affiliation: Utility Air Regulatory Group
Document Control Number: EPA-HQ-OAR-2002-0058-2880.1
Comment Excerpt Number: 70

Comment: Proposed § 63.7505(d) states that units that "demonstrate compliance with any applicable emission limit through performance stack testing . . . must develop a site-specific monitoring plan according to . . . paragraphs (d)(1) through (4)." 75 Fed. Reg. at 32,050. Paragraphs (d)(1) through (4), address requirements for "each CMS required in this section." However, proposed § 63.7505 does not appear to require any CMS. The only reference to CMS in that section is to the fact that source owners/operators may demonstrate compliance using the CMS "where applicable." As a result, applicability of the requirements in (d)(1) - (4) is not clear.

Response: A full response to this comment is currently in development and will be added when it is complete.

Commenter Name: Lee B. Zeugin
Commenter Affiliation: Utility Air Regulatory Group
Document Control Number: EPA-HQ-OAR-2002-0058-2880.1
Comment Excerpt Number: 71

Comment: Proposed § 63.7510(a) states that affected sources that elect to demonstrate compliance using performance stack test and that "burn a single type of fuel" are "exempted from the initial compliance requirements of conducting a fuel analysis for each type of fuel burned." 75 Fed. Reg. at 32,051. However, proposed § 63.7530(b), which contain the fuel analysis requirements for units demonstrating compliance through performance testing, does not exempt fuel analysis. It only exempts determination of the fraction of total heat input for that fuel type. Proposed § 63.7530(b)(1)(iii). As a result, the meaning and applicability of the exception in proposed § 63.7510(a) is not clear.

Response: EPA has added language to 63.7530(b) within the final rule to clarify that the fuel analysis is not needed if only a single fuel is used.

Commenter Name: Lee B. Zeugin
Commenter Affiliation: Utility Air Regulatory Group
Document Control Number: EPA-HQ-OAR-2002-0058-2880.1
Comment Excerpt Number: 74

Comment: Proposed § 63.7525(c)(7) requires source owners/operators to "determine and record all the 6-minute averages (and 1-hour block averages as applicable) collected for periods" during which the COMS is not out of control. 75 Fed. Reg. at 32,055-56. The reference to "1-hour block" averages is not clear. The proposed rule requires reduction of data to 6-minute averages and compliance with a 24-hour (or daily) block average.

Response: EPA has revised 63.7525(c)(7) in the final rule and changed the "1-hour block" to "daily block."

Commenter Name: Lee B. Zeugin
Commenter Affiliation: Utility Air Regulatory Group
Document Control Number: EPA-HQ-OAR-2002-0058-2880.1
Comment Excerpt Number: 75

Comment: Proposed §63.7525(d)(4) requires determination of the "3-hour block average" of all recorded readings from CPMS. 75 Fed. Reg. at 32,056. Since the rule does not use 3-hour averages, this provision makes no sense.

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-2777.1, Excerpt Number 44 to view the response.
EPA has revised 63.7525(d)(4) within the final rule to 4-hour block averages for CPMS.

Commenter Name: Lee B. Zeugin
Commenter Affiliation: Utility Air Regulatory Group
Document Control Number: EPA-HQ-OAR-2002-0058-2880.1
Comment Excerpt Number: 77

Comment: Although UARG does not believe PM CEMS should (or can) be required for compliance determinations under this rule, UARG notes that EPA's proposed rule, which does provide for use of a PM CEMS, does not exempt those units from the other performance testing and operating limit requirements in proposed § 63.7530 and § 63.7515. In fact, in the preamble, EPA states that compliance with PM standards is always determined by "initial and annual stack tests . . . using EPA Method 5 or 17." 75 Fed. Reg. 32,013. This statement is inconsistent with the proposed 63.7510(d).

Response: EPA has revised 63.7510(d) within the final rule to add a sentence saying that boilers and process heaters that use a CEMS for PM are exempt from the performance testing and operating limit requirements specified in paragraph (a) of that section (63.7510).

Commenter Name: Lee B. Zeugin
Commenter Affiliation: Utility Air Regulatory Group
Document Control Number: EPA-HQ-OAR-2002-0058-2880.1
Comment Excerpt Number: 78

Comment: The references to equation 8 in proposed § 63.7530(c)(3) and (c)(4) are incorrect. 75 Fed. Reg. 32,057-58.

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-2960.1, Excerpt Number 182 to view the response.

Commenter Name: Lee B. Zeugin
Commenter Affiliation: Utility Air Regulatory Group
Document Control Number: EPA-HQ-OAR-2002-0058-2880.1
Comment Excerpt Number: 79

Comment: Proposed § 63.7530(d) identifies a different applicability threshold for the work practice standard than other provisions. According to proposed Tables 2 and 3, and the preamble, the emission limits for existing units apply to units with heat input capacity of "10 million Btu per hour or greater" and the work practice standard applies to units with heat input capacity "less than" 10 mmBtu/hr. 75 Fed. Reg. at 32,012. Proposed § 63.7530(d) on the other hand refers to units with heat input capacity of "10 mmBtu per hour or less." 75 Fed. Reg. at 32,058. EPA should correct this inconsistency.

Response: EPA has revised the criteria to "less than".

Commenter Name: Lee B. Zeugin
Commenter Affiliation: Utility Air Regulatory Group
Document Control Number: EPA-HQ-OAR-2002-0058-2880.1
Comment Excerpt Number: 80

Comment: Almost all of the equation references in proposed § 63.7540(a)(3) - (6) are incorrect. 75 Fed. Reg. at 32,058-59.

Response: EPA has checked and corrected the equation references in these paragraphs.

Commenter Name: Lee B. Zeugin
Commenter Affiliation: Utility Air Regulatory Group
Document Control Number: EPA-HQ-OAR-2002-0058-2880.1
Comment Excerpt Number: 81

Comment: Proposed § 63.7540(a)(4) incorrectly references § 63.7530(c) as the provision for establishing operating limits for units that demonstrate compliance through performance testing. 75 Fed. Reg. at 32,058.

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-2880.1, Excerpt Number 80 to view the response.

Commenter Name: Lee B. Zeugin
Commenter Affiliation: Utility Air Regulatory Group
Document Control Number: EPA-HQ-OAR-2002-0058-2880.1
Comment Excerpt Number: 82

Comment: Although proposed § 63.7515(e) requires all units subject to work practice standards to perform a "tune-up" annually, proposed § 63.7540(a)(11) states that boiler and process heaters with heat input capacity less than 10 mm/Btu/hr must perform "tune-ups" biennially. 75 Fed. Reg. at 32,052, 32,059.

Response: EPA has updated 63.7515(e) to reflected the corrections suggested within this comment.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 236

Comment: The following are several technical or reference errors noted in the proposed rule that require correction:

Section 63.7515(e) states that facilities must conduct tune-ups according to 63.7520, but there are no tune-up requirements in the referenced section . We believe the correct reference is 63.7540.

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-2525.1, Excerpt Number 18 to view the response.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 237

Comment: Section 63.7525(f)(1) refers to "actual heat capacity" but we believe this should be "actual heat input" as the variable Hb is defined following Equation 3.

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-3211.1, Excerpt Number 311 to view the response.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 239

Comment: In the proposed section 63.7525(a), EPA specifies that a CO CEMS must be installed on all boilers and process heaters that are more than 100 MM Btu/hr. This language would require that a CO CEMS be installed on all existing and new Gas 1-fired units. However, EPA did not establish CO limits for these units, so it should not be necessary to install a CO CEMS.

We recommend that EPA eliminate this confusion by re-writing the first sentence of 63.7525(a) to read: "If your boiler or process heater has a CO limitation and has a heat input of 100 MMBtu per hour or greater...."

Response: EPA has revised 63.7525(a) within the final rule to clarify that only applies to units with CO limits

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Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 241

Comment: ACC believes that section 63.7525(i), which contains requirements for equipment used to measure sorbent injection rate, incorrectly requires compliance with the requirements in paragraph (c), which contains requirements for COMS.

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-3213.1, Excerpt Number 316 to view the response.
EPA has updated the final review to correct typos and reference errors, and (c) has been corrected to (d).

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 242

Comment: Section 63.7530 (b) should reference Table 4 for establishing operating limits instead of Table 2, which contains emission limits.

Response: EPA has updated the final rule to correct reference errors and has correct the Table 4 reference.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 243

Comment: At section 63.7530(b)(3), the reference should be (b)(3)(i) through (iv), not (c)(4)(i) thru (iv).

Section 63.7530(b)(3)(ii) seems to require setting secondary voltage and current operating ranges for all ESP's, whether or not they are followed by additional wet control. This language is in conflict with Table 4 (Item 3) and Table 7 (Item 1.b). EPA should clarify the language in section 63.7530(b)(3)(ii) to indicate that ESP parameter operating ranges should only be set if the ESP is followed by a wet control device.

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-3213.1, Excerpt Number 318 to view the response.
EPA has revised the section to clarify the applicability.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 244

Comment: In section 63.7555(d)(3), there is an extraneous requirement to maintain records of monthly hours of operation for limited use boilers. Unless EPA plans to create a subcategory for limited use boilers, as we recommend elsewhere in these comments, this requirement should be removed as there is no exemption for limited use boilers in the proposed rule.

Response: This comment has previously been addressed. Please refer to comment EPA-HQ-2002-0058-2757.1, Excerpt Number 2 to view the response.

Other - Rule Language Corrections

Commenter Name: Terry L. O'Clair
Commenter Affiliation: North Dakota Department of Health
Document Control Number: EPA-HQ-OAR-2002-0058-3140
Comment Excerpt Number: 8

Comment: Although the format of the proposed rule may technically be adequate, the proposed rule is difficult to read and interpret. Many sources that will be subject to this rule are not large entities with specialized environmental staff. Therefore, we strongly recommend that EPA write the rule in a more readable format to enable the regulated community to better understand and meet the requirements. Simply providing implementation tools such as fact sheets and memos will not meet the need for a clear, concise and readable rule.

Response: We have modified and corrected several reference errors in response to public comments and modified regulatory strategies. EPA will conduct training sessions on this rule and be available to answer technical rule implementation questions.

Commenter Name: Sonnichsen Engineering, LLC
Commenter Affiliation: Tim W. Sonnichsen
Document Control Number: EPA-HQ-OAR-2002-0058-2931.1
Comment Excerpt Number: 13

Comment: The MACT Rules are all but unreadable
Owners, managers and operators of biomass-fired boilers are very busy people. The length, format and the rambling question-and-answer nature of the MACT "rule" are not acceptable.

In preparing the final rule, kindly provide summary documents that are clear , concise, and to the point. If you must include an additional 200 to 300 pages for the lawyers to decipher, then so be it.

Response: We have modified and corrected several reference errors in response to public comments and modified regulatory strategies and streamlined requirements, when appropriate. EPA will continue to develop trainings on this rule to inform the regulated community.

Startup, Shutdown, and Malfunction (SSM)

SSM Regulatory Text Provisions

Commenter Name: Arlington Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1779
Comment Excerpt Number: 102

Comment: At refineries and chemical plants it is well established from state emissions data that there have been decades of routine violations of emission standards during so-called malfunction events.

When these events happen, the neighboring communities are blanketed in toxic emissions. People are made sick immediately. They lose work days. They have to visit doctors and seek medical care that many can't afford. Their children miss school. And because the emissions are so toxic it also increases their chances of catastrophic health effects like cancer and birth defects.

Now, this exemption has been ruled unlawful by a Federal Court of Appeals. We hope that EPA will be taking it out of other rules but taking it out of this rule which governs thousands of major sources of hazardous air pollutants, including many of the worst abusers of the exemption, will go a long way by making them run their sources cleanly or be held accountable; and we think this is very important.

Response: See preamble for response to changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Bill Wemhoff
Commenter Affiliation: National Rural Electric Cooperative Association
Document Control Number: EPA-HQ-OAR-2002-0058-2835.1
Comment Excerpt Number: 15

Comment: EPA's promise to address periods of equipment malfunction by considering other information before enforcing exceedance of operating limits also provides little comfort, especially given the risk of citizen suits. Although NREGA appreciates EPA's proposal to make clear that "deviations" of operating limits are not necessarily violations, nothing in EPA's proposal would prevent EPA, a state, or a plaintiff in a citizen suit from simply determining in their "discretion" that any particular exceedance constitutes a violation. MACT standards are technology-based standards, and NREGA believes the agency must recognize that even the best performing technology occasionally fails.

Response: See preamble for response to changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Sheila C. Holman
Commenter Affiliation: North Carolina Department of Environment and Natural Resources
Document Control Number: EPA-HQ-OAR-2002-0058-2798.1
Comment Excerpt Number: 15

Comment: It should be clarified that EPA established only one-of-the-five pollutants' standards (CO) with emission data collected during startup and shutdown periods. EPA can mislead readers to infer that all standards were based with startup and shutdown data by stating on pp. 32012-13 that "Din establishing the standards in this rule, EPA has taken into account startup and shutdown periods..." EPA should clarify that PM, HCI, Hg, and dioxins emission data were not collected during startups and shutdowns, but rather during typical, steady-state (if not best) conditions.

Response: See the preamble for response to how EPA adjusted CO emission limits and compliance mechanisms, and changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Sheila C. Holman
Commenter Affiliation: North Carolina Department of Environment and Natural Resources
Document Control Number: EPA-HQ-OAR-2002-0058-2798.1
Comment Excerpt Number: 16

Comment: The NC DAQ has developed SSM provisions for related plan requirements, recordkeeping, and reporting that have been accepted by and are working for some of our Title V permitted facilities. Such provisions are worthy of EPA consideration and include:

NC agrees that emission data from malfunctions should not be included in evaluation against the standards because it would be impracticable and problematic, given that malfunctions can vary in frequency, degree, and duration, further complicating standard setting.

Malfunction emission counting notwithstanding, some form of constraint and accountability needs to be placed on malfunctions through integrated documentation with the facility standard operating procedures (SOPs) and/or maintenance manuals.

To be considered a malfunction, the breakdown must be unforeseeable and un preventable. A foreseeable and preventable breakdown is not regarded as a malfunction, but rather a failure of good operation and maintenance using best practices, triggering a notice of violation and possibly an enforcement fine.

Facility CEM data are reviewed to determine the percentage of time specific emission control equipment is in startup, shutdown, malfunction, and other excess emission periods. NC DAQ has established a Continuous Monitoring Enforcement Plan (CEP) which sets maximum excess emission period levels not to be exceeded. These maximum levels include excess emission periods during startup, shutdown, malfunction, known events, and unknown events. Periods of excess emissions during 3- or s-mornh periods are allowed up to their respective time limits, as long as the explanations of the excess emissions events meet the definitions of startup, shutdown, and malfunction. When any 3- or 6-month excess emission level is exceeded, the facility is deemed in non-compliance with 40 CFR 63.94 and NC rules. Although NC DAQ evaluates excess emissions on a broader range (i.e., we also count known and unknown event periods), we recommend EPA stay with the strict definition of SSM when applying this concept by not including known and unknown excess emissions in the calculation.

NC has a longstanding regulation for evaluating and exempting malfunctions for non·MACT sources. North Carolina Administrative Code 2D.0535 requires NC DAQ to consider at least the same elements that EPA has stated on page 32013 of the proposed rule for malfunction evaluation. In order for the agency to review a malfunction, the facility must meet the following requirements:

The owner or operator of a source of excess emissions that last for more than four hours and results from a malfunction, a breakdown of process or control equipment or any other abnormal conditions, shall:

(1) Notify the permitting agency of any such occurrence by 9:00 am of the agency's next business day of becoming aware of the occurrence and describe:

(A) Name and location of the facility,

(B) The nature and cause of the malfunction or breakdown,

(C) The time when the malfunction or breakdown is first observed. (D) The expected duration, and

(E) An estimated rate of emissions;

(2) Notify the permitting agency immediately when the corrective measures have been accomplished;

(3) Submit to the permitting agency Within 15 days atter the request a written report that includes:

(A) Name and location of the facility,

(B) Identification or description of the processes and control devices involved in the malfunction or breakdown,

(C) The cause and nature of the event,

(D) Time and duration of the violation or the expected duration of the excess emission if the malfunction or breakdown has not been fixed,

(E) Estimated quantity of pollutant emitted,

The owner or operator of a source of excess emissions that last for more than four hours and results from a malfunction, a breakdown of process or control equipment or any other abnormal conditions, shall:

(1) Notify the permitting agency of any such occurrence by 9:00 am of the agency's next business day of becoming aware of the occurrence and describe:

(A) Name and location of the facility,

(B) The nature and cause of the malfunction or breakdown,

(C) The time when the malfunction or breakdown is first observed. (D) The expected duration, and

(E) An estimated rate of emissions;

(2) Notify the permitting agency immediately when the corrective measures have been accomplished;

(3) Submit to the permitting agency Within 15 days atter the request a written report that includes:

(A) Name and location of the facility,

(B) Identification or description of the processes and control devices involved in the malfunction or breakdown,

(C) The cause and nature of the event,

(D) Time and duration of the violation or the expected duration of the excess emission if the malfunction or breakdown has not been fixed,

(E) Estimated quantity of pollutant emitted, fixed, steps planned to be taken, and

(G) Any other pertinent information requested by the permitting authority.

Normally most of the malfunction report elements come with initial contact by the next business morning. NC facilities frequently contact OAQ for assistance early in an incident. Prompt response by the agency can often help shorten or reduce the period of excess emissions.

A similar set of requirements for malfunction reporting can be included in the Boiler MACT. For malfunctions to be evaluated quickly and effectively, burden for implementation would have to fall on the permitting agency. Whether a request threshold of two, three or four hours should be included in the language is discretionary. Such a threshold could prevent excessive burden on permitting agencies for evaluations and still provide facilities some relief for more serious and complicated incidents. The final written report could follow 5 or less days following the end of the malfunction.

Response: See the preamble for response to how EPA adjusted CO emission limits and compliance mechanisms, and changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Ted Michaels
Commenter Affiliation: Energy Recovery Council
Document Control Number: EPA-HQ-OAR-2002-0058-2831.1
Comment Excerpt Number: 16

Comment: Citing a 2008 court decision (Sierra Club v. EPA) related to General Provisions under 40 CFR Part 63, EPA has proposed that Major Boiler MACT emission standards apply at all times, including during periods of startup, shutdown and malfunction (SSM). EPA acknowledges that the Court's decision did not specifically address category-specific SSM provisions. We believe that EPA is over-stepping its authority to void longstanding category-specific SSM provisions.

Response: See the preamble for response to changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Steven G. Hanson
Commenter Affiliation: Graphic Packaging International
Document Control Number: EPA-HQ-OAR-2002-0058-2723.1
Comment Excerpt Number: 17

Comment: EPA has a responsibility to set and enforce limits that a source can meet (i.e., achievable), not create a limit that is unattainable by any source in the US, new or existing. The proposed approach is the equivalent to setting the speed limit at an oncoming ramp to an interstate at 5 mph, and then expecting the car to immediately reach the speed of interstate traffic (55 mph or more) with no adverse events. The expectation of a source to comply immediately upon startup, which is known to have higher CO emissions,[While GPI does not have a CO CEM on the existing biomass boiler to support this statement, the Recovery Furnace CO CEM does she a pattern of higher CO emissions during startup procedures. This stems in part from the use of fossil fuel in the boiler during startup and the need to bring the furnace up to the typical combustion temperature. A similar trend would be expected in a woody biomass boiler.] without taking into account these emissions when setting the MACT floor, is no different. While EPA states that startup and shutdown data have been used to establish the standards, this statement is false for biomass stokers and biomass fluidized bed boilers. GPI — Macon Mill urges EPA to reconsider emissions during startup and shutdown. Accordingly, GPI — Macon Mill contends that EPA needs to establish separate emission limitation or, preferably, work practice standards specific to startup and shutdown operations.

Response: See the preamble for response to how EPA adjusted CO emission limits and compliance mechanisms, and changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Ted Michaels
Commenter Affiliation: Energy Recovery Council
Document Control Number: EPA-HQ-OAR-2002-0058-2831.1
Comment Excerpt Number: 17

Comment: Aside from this legal deficiency, EPA's proposed floor setting methodology fails to adequately consider emissions variability that occurs during SSM periods. In its proposal EPA asserts that "[t]he standards we are proposing are daily or monthly averages ... [t]hus, we are not establishing separate emission standards for these periods because startup and shutdown are part of their routine operations and, therefore, are already addressed by the standards." (75 FR 32013). However, EPA uses short term performance test results rather than the results of long-term CEMS monitoring to set the floors, the only exception for biomass boilers being CO CEMS analysis on only two units. As a result, the emissions data on which the floors are based do not, in fact, reflect or adequately accommodate emissions during SSM periods. Furthermore, EPA's daily average only applies to CEM pollutants. Most emissions (HCl, mercury, dioxin/furan) are tested using EPA Reference Methods which determine emissions over a three to twelve hour average. Neither EPA's emission limits nor compliance averaging times adequately accommodate variability in emissions due to SSM.

Emissions can be significantly higher during SSM due to the unavoidable less-thanoptimal emissions control performance during transitional (non-steady state) conditions. For example, at biomass-to-energy facilities combustion-related emissions such as CO, particulate (smoke) and opacity increase during the startup period when load and temperature are coming up to full load steady-state conditions. The Maine Department of Environmental Protection has stated "Wood and multi-fueled boilers produce large CO variations during startups as the boiler heats up. Start-ups can take up to 14 hours for some units. Shutdowns can also result in significant CO variability."[Letter James P. Brooks, Bureau Director, State of Maine Bureau of Air Quality to James Eddinger, USEPA, February 4, 2010.]

(See submittal for ME DEP report] Startup burners reduce emissions by preheating the combustion chamber and downstream equipment but are not sized to achieve full load temperatures and even if they were could not completely avoid temporary sub-optimal combustion conditions as heat load shifts from auxiliary fuel to waste during startup and from waste to auxiliary fuel during shutdown. Air pollution control equipment goes through similar transient temperature and flow conditions. These conditions are distinct from the variable conditions that occur during normal operation. EPA's emission database excludes SSM periods and therefore does not capture this component of variability, leading to MACT floors that have not been achieved in practice. [See submittal for example CO concentrations during startup and shutdown.]

EPA should set standards which incorporate SSM emissions. There are a few options. First, EPA could set standards applicable at all times which reflect the emissions variability inclusive of SSM. Second, EPA could set distinct standards which would apply only during SSM periods. Both these options are problematic - since its emission database does not contain SSM data EPA would need to gather additional test data for the various categories and units. EPA could use certified continuous emissions monitoring data for those few pollutants that are continuously monitored, but non-CEM pollutant data would likely be unavailable and involve a costly and time-consuming effort to collect using manual methods. Collecting non-CEM pollutant data is further complicated by the fact that EPA's stack testing procedures (40 CFR 60, Appendix A) require that testing be conducted under steady state conditions.

Response: See the preamble for response to how EPA adjusted CO emission limits and compliance mechanisms, and changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: American Crystal Sugar Company and Michigan Sugar Company
Commenter Affiliation: Patricia Hansen and Steven Smock
Document Control Number: EPA-HQ-OAR-2002-0058-2970.1
Comment Excerpt Number: 17

Comment: If Start-up, Shut-down and Malfunctions are considered to be part of normal operations during which compliance must be maintained, then it is only logical that some of the data evaluated to determine the MACT floor must incorporate these time periods somehow. Obviously malfunctions are unpredictable as stated in the preamble and cannot be tested. Furthermore various malfunctions will likely have different effects on the emissions making evaluation even more difficult. However, start-ups can be predicted and could be evaluated. It is recommended that the top performing boilers be retested or monitored with the appropriate CEM to determine the effect a start-up and shut-down has on the emissions and how the limits should be adjusted. To set the limits without even knowing the effect of these events and expect compliance during them may be setting up every source for failure. At this point we simply do not know the outcome.

Response: See the preamble for response to how EPA adjusted CO emission limits and compliance mechanisms, and changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Lee B. Zeugin
Commenter Affiliation: Utility Air Regulatory Group
Document Control Number: EPA-HQ-OAR-2002-0058-2880.1
Comment Excerpt Number: 17

Comment: Compliance with the proposed CO limits is problematic particularly during unit startups. As discussed in section I.H. above, there is no factual support for EPA's conclusion that the CO standard is "achievable" during plant startup. No CO emissions testing was conducted during plant startup of biomass units. Startup of a biomass can take up to a day. During startup, work practice standards are more appropriate than CO emission limits.

Response: See the preamble for response to how EPA adjusted CO emission limits and compliance mechanisms, and changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: David W. Peightal
Commenter Affiliation: Dakota Gasification Company
Document Control Number: EPA-HQ-OAR-2002-0058-3179
Comment Excerpt Number: 18

Comment: Sampling methods used to gather data for forming the MACT floors must be standardized so that the dataset integrity is maintained and consistent with reporting methods. Since there are no proposed SSM exceptions, data must reflect the inclusion of start-ups and shutdowns to be relevant. Sampling done during steady state operating conditions will not reflect variable conditions that are present during start-up/shutdown periods. DGC requests a more extensive sampling effort to expand the dataset used to determine the MACT floors.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Steven G. Hanson
Commenter Affiliation: Graphic Packaging International
Document Control Number: EPA-HQ-OAR-2002-0058-2723.1
Comment Excerpt Number: 18

Comment: GPI — Macon Mill contends that EPA should establish work practice requirements to address malfunction events. In the reality of manufacturing operations, malfunctions do occur. Per 40 CFR 60.2, EPA has defined malfunctions as sudden, infrequent and not reasonably preventable failure of air pollution control and monitoring equipment, process equipment or a process to operate in a normal or usual manner.... As EPA has already noted, per this defmition, malfunctions are "not reasonably preventable" and are clearly distinct from normal, startup, or shutdown operations; it does not make sense that EPA then concludes, on page 32013 of the Federal Register, that malfunctions should not be viewed as a distinct operating mode and, therefore, any emissions that occur at such times do not need to be factored into development of the CAA Section 112(d) standards, which, once promulgated, apply at all times. Even the "best perfolining- sources will encounter malfunction events — it is a practical reality. GPI — Macon Mill encourages EPA to consider a work practice standard similar to the prior requirement for a plan to operate in a manner that minimizes the emissions of pollutants during a malfunction event.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Robert Thornton
Commenter Affiliation: International District Energy Association
Document Control Number: EPA-HQ-OAR-2002-0058-2918.1
Comment Excerpt Number: 18

Comment: EPA makes a similar mistake with regard to its proposal not to set a separate standard for periods of startup, shutdown, and malfunction. On the one hand, EPA asserts that "[t]he standards we are proposing are daily or monthly averages ... [t]hus, we are not establishing separate emission standards for these periods because startup and shutdown are part of their routine operations and, therefore, are already addressed by the standards." On the other hand, EPA uses short term performance test results to set the standards rather than the results of long-term CEMS monitoring. As a result, the emissions data on which the standards are based do not, in fact, reflect or adequately accommodate emissions from periods of startup, shutdown, or malfunction.

EPA must use data to set the standard that are consistent with the form of the standard. As compliance with the CO standard is to be measured at all times using CO CEMS for units of 100 MMBtu/hr and greater and the averaging time is 30 days, EPA should use 30-day CEMS data from affected boilers to establish the appropriate MACT floors and not 3-run stack test data.

To assure that startup, shutdown, and malfunction are appropriately accommodated, EPA must either assure that the data on which the standard is based include representative data from such periods or, alternatively, set a separate work practice standard to properly accommodate startup, shutdown, and malfunction.

Response: See the preamble for response to how EPA adjusted CO emission limits and compliance mechanisms, and changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Ted Michaels

Commenter Affiliation: Energy Recovery Council
Document Control Number: EPA-HQ-OAR-2002-0058-2831.1
Comment Excerpt Number: 18

Comment: There are also difficulties trying to set concentration-based standards corrected to a standard diluent concentration (e.g., ppmdv @ 3% O2) for startup and shutdown periods. Emission concentrations soar artificially due to the exponentially increasing correction factor as the stack oxygen concentration approaches ambient levels and CO_2 concentrations approach zero. At low unit loads at the beginning of startup or at the end of shutdown corrected emission concentrations could be very high giving the appearance of significant emissions when the actual mass emissions (pounds per hour) are small due to the lower stack volumetric flow rates. If EPA decides to set concentration standards for SSM periods it should recognize the diluents caps of 14 percent for oxygen or 5 percent for carbon dioxide in emission calculations as is currently done in the Large MWC MACT rule (40 CFR 60.58b (b)(8)).

ERC supports a third option for a boiler MACT SSM standard which solves both the data availability and concentration-based standards problems. This approach would require that each State address SSM emission standards in its State Implementation Plans (SIP). The SIP would specify a procedure which would be used to set mass emission standards (e.g., pounds per startup period) for each subcategory and unit case-by-case based on emissions reductions achieved using accepted startup, shutdown and malfunction related procedures. For example, for a unit using an auxiliary burner for startup the CO standard (pounds per startup) would be set considering the limitations of the properly operated burner and boiler design during a defined startup period. SSM emissions would be minimized by the same emission reduction technologies that would enable units to comply with all Major Boiler MACT standards and would thus represent a small component of a unit's annual emissions. The case-by-case SSM emission limits would be written into facility permits and become federally enforceable mass emission standards. The unit's continuous emission monitoring system (CEMS) would be used to calculate and report mass emissions during SSM periods.

Response: See the preamble for response to how EPA adjusted CO emission limits and compliance mechanisms, and changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Gordon M. Smith
Commenter Affiliation: Mitsubishi Polyester Film, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2912
Comment Excerpt Number: 18

Comment: According to §63.7505, the requirements of the proposed rule apply at all times. However, it is clear that no startup and shutdown emission data was included in the database used to generate the proposed emission limits and that boilers and process heaters cannot meet all of the proposed emission limitations during all periods of startup and shutdown. In fact, it is forbidden by §63.7(e) of the Part 63 General Provisions for performance tests to include startup, shutdown or malfunction periods in performance tests. Even units that can be retrofitted with controls that allow achieving the emission limits during normal operations will be unable to meet the limits during some startups and shutdowns, because many of the controls are not effective at the low stack temperatures that occur during startup and shutdown periods.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Gordon M. Smith
Commenter Affiliation: Mitsubishi Polyester Film, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2912
Comment Excerpt Number: 20

Comment: The issue of the impacts of startups and shutdowns on emissions of other pollutants are not discussed. Emissions result from pollutants contained in fuel (i.e., Hg and Cl-) are unlikely to be different during startup and shutdown periods, but a simple understanding of combustions suggest that particulate emissions are likely to be higher during poor combustion periods such as occur during these times. The impact of startup and shutdown conditions on dioxin/furan emissions is unknown, but that provides little certainty for sources that will have to certify that they complied with the dioxin/furan limits during these periods. Since there is no significant averaging period provided for PM or dioxin/furan, any excursion during a startup or shutdown would presumably generate a deviation.

For pollutants other than CO, there is less information on how they behave during startup and shutdowns, but since those are inherently periods of poor combustion and unstable control operation, we would expect there to be some exceedances. For instance, the temperature of the stack gas going into the activated carbon absorption system will vary from ideal during startup and shutdown operations and thus mercury and dioxin removal will be less efficient than during normal operations.

Response: See the preamble for response to how EPA adjusted CO emission limits and compliance mechanisms, and changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Gordon M. Smith
Commenter Affiliation: Mitsubishi Polyester Film, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2912
Comment Excerpt Number: 21

Comment: The Agency also claims that startup and shutdowns are predictable and do not happen more than once per day. If emissions during startups and shutdowns are different than during normal operation, which they are, it doesn’t matter that the startup or shutdown was

predictable. The compliance average will still be impacted the same. The Agency's assumption that startups and shutdowns generally do not occur more than once per day is correct, though startups often take more than a day to complete and most take a significant part of a day. The number of startups in a day does not matter, however; what matters is the level of emissions during the startup or shutdown and the duration of those emissions relative to the averaging time of the standard. For CO, units with CEMS (units over 100 MMBTU/hr) having a 30 day averaging time, it only takes 1 day at 30 ppm to exceed the standard and such days will be the rule rather than the exception during boiler and process heater startups.
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Response: See the preamble for response to how EPA adjusted CO emission limits and compliance mechanisms, and changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Gordon M. Smith
Commenter Affiliation: Mitsubishi Polyester Film, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2912
Comment Excerpt Number: 22

Comment: Since it is not feasible for boilers or process heaters, to meet all of the emission limits during certain startups and shutdowns, work practice requirements should be specified as provided for in §112(h).

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Gary W. Kruger
Commenter Affiliation: Morton Salt
Document Control Number: EPA-HQ-OAR-2002-0058-2883.1
Comment Excerpt Number: 24

Comment: EPA stated that CEMs data from best-performing units included periods of startup and shutdown, and therefore EPA's proposed standards are achievable.
To support its conclusion that the proposed emission standards should apply during all operational periods, including during SSM events, EPA asserts that startup and shutdown emissions replicate normal operation emissions. These conclusions are not supported by the record. EPA relied on continuous emission monitoring (CEMs) data obtained from best performing units, which EPA claims included periods of startup and shutdown. It is unclear whether this CEMs data actually warrants these conclusions. It does not appear that any of the units considered in the data collection were in startup or shutdown during the 30-day period of testing that EPA considered. Assuming that is the case, then the CEMs data does not demonstrate

that units can satisfy emissions limits over a 30-day period if all startup and shutdown events are included.
EPA is also operating on the misconception that solid fuel fired boilers do not normally start up and shutdown more than once per day and that startup and shutdown are part of routine operations and, therefore, are already addressed by the standards. 75 Fed. Reg. at 33,012. However, circumstances may necessitate multiple startups and shutdowns throughout a day for many boilers. The CAA has been interpreted to require that emissions standards be achievable under the most adverse conditions that can be expected to occur, not under assumptions of what is normally done or not done. EPA has not demonstrated startup and shutdown periods were actually considered even though the proposed rule establishes emissions standards that apply to units during steady-state operations as well as such periods.
Another concern is that EPA used 3-run stack test data, and not 30-day data, to set the proposed emissions floors. EPA has used test run data collected through the ICR phase II to establish proposed floors which reflect normal, often steady state, operating conditions. EPA's docket materials in support of the proposed rule even acknowledge that this data fails to account for the dynamic conditions and variable emissions occurring during startup and shutdown episodes. This test data also does not utilize the CEMs data, including startup and shutdown information, in its variability analysis where it would be the most helpful in reflecting real-world fluctuations in emissions.

Response: See the preamble for response to how EPA adjusted CO emission limits and compliance mechanisms, and changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Gary W. Kruger
Commenter Affiliation: Morton Salt
Document Control Number: EPA-HQ-OAR-2002-0058-2883.1
Comment Excerpt Number: 25

Comment: The current decision by EPA to exclude startup, shutdown, and malfunction emissions records is technically unjustified. A series of previous emission control programs over the last 25 years has resulted in the installation of several systems to achieve specific emission reductions through targeted technologies, but most are designed for steady state or normal operations.
The first of these was implemented under the CAA revision of 1990 that required units larger than 25 MWe to reduce sulfur emissions below 1.2 lb/MMbtu and achieve at least a 90% reduction. One of the few methods of doing this that could survive severe abrasive characteristics present in some units was dry limestone injection. This process is dependent on injection of sized limestone into the furnace/boiler, calcinations of the limestone, and subsequent absorption of sulfur present in the flue gas. This process begins to occur at a useful rate at about 860 deg. F and is functional up to about 2200 deg. F. (Unfortunately at about 1640 deg. F thermal NOx generation normally inhibits operation above that temperature.) For a boiler to achieve the lower useful temperature of 860 deg. F, it must be heated up to that level, generally using natural gas or fuel oil. This thermal change to the materials that boilers are fabricated with is limited by

impacts of thermal stresses placed on both the generating tubes and drum materials, by the manufacturers to a change rate of 100 deg. F. Thus, to take a unit from cold to the functional temperature that limestone becomes effective for SO2 removal, takes a minimum of about 8 to 10 hours. Application of 'normal steady state' limits based on a temperature of 1600 deg. is not practical. Due to the high volume of combustion air involved, most casualties result in the unit falling outside of the optimum band for absorption also, so achievement of the limits during these periods is technically infeasible.

EPA has long recognized that control and/or monitoring equipment is not necessarily functional during SSM periods. In developing the SSM approach in the General Provisions, EPA recognized the difficulty of determining compliance during SSM periods. 58 Fed. Reg. 42,777 (Aug. 11, 1993). EPA adopted an approach whereby an owner of an affected facility who abides by a valid SSM plan during SSM periods would not be deemed in violation of the applicable standard. EPA stated:

This approach carries forward the requirement that control systems be operated at all times, but it allows special situations to occur, such as unpredicted and reasonably unavoidable failures of air pollution control systems, when it is technically impossible to properly operate these systems. 58 Fed. Reg. 42,777 (Aug. 11, 1993).

In the preamble to the final General Provisions, EPA responded to one commenter who said EPA should require affected sources to meet otherwise applicable emission limits during startups, shutdowns, and malfunctions. EPA said it believes, as it did at proposal, that the requirement for a startup, shutdown, and malfunction plan is a reasonable bridge between the difficulty associated with determining compliance with an emission standard during these events and a blanket exemption from emission limits. 59 Fed. Reg. 12,423 (Mar. 16, 1994). Morton Salt believes EPA's rationale is sound in this case, and it also applies to affected sources subject to the Boiler MACT standards and we fully support retaining this approach to startup, shutdown and malfunction in the final regulations.

Response: See the preamble changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Gary W. Kruger
Commenter Affiliation: Morton Salt
Document Control Number: EPA-HQ-OAR-2002-0058-2883.1
Comment Excerpt Number: 26

Comment: An Extended Averaging Period Will Not Eliminate Problems With Making Emissions Limits Applicable During Startup and Shutdown Periods

Institutional, commercial and industrial boilers require an extended period of startup during which most, if not all, equipment in the boiler and pollution control systems are not operating in their normal condition. Consequently, pollutant emission concentrations and emission rates can exceed those experienced during normal operation. It is very common in the boiler industry for certain control devices to be out of operation during periods of startup due to the nature of the equipment. During such periods it is likely that emissions will exceed the standards proposed and would never be able to recover to meet the average limitations. A more expanded discussion with respect to a few specific technologies is provided below. This extended startup period, typically several hours, is required due to equipment integrity concerns, limitations of the technologies, or safety concerns.

Equipment Integrity - As an example, a Fabric Filter (FF) cannot be put into service until the flue gas temperature is above the dewpoint for equipment integrity concerns. This requires that all heat transfer surfaces, ducts and flues from the combustion zone to the FF inlet be warmed up from ambient temperatures to dewpoint temperature (which varies by fuel type and fuel constituents, but is typically in excess of 140°F /60°C). It takes a considerable amount of time, typically several hours for larger units, to warm up this considerable mass of steel: waterwall tubes, superheater tubes, reheater tubes, economizer tubes, casings, turning vanes, air preheaters, ducts and inlet plenums. During this warmup period, the FF cannot be put into service without risking catastrophic failure of the bags and intensive corrosion damage to the FF due to acid dew point and other factors. This limits a unit's ability to control Particulate Matter and Mercury during the several hours of startup.

Limitations of the Technology - Limitations of the pollutant control technology also contribute to extended startup periods and excess emissions. Units equipped with a Spray Dryer Absorber (SDA) for acid gas removal are limited in the amount of reagent slurry that can be injected into the flue gas during startup. The slurry federate is limited due to the nature of the technology bythe amount of moisture the flue gas can evaporate. This, in turn, requires that a minimum temperature be achieved by the flue gas before the slurry federate can be initiated, and imposes a lengthy period of time during which the slurry federate is significantly limited until all the upstream heat transfer surface and ductwork has been warmed up. As such, SDA cannot remove Hydrogen Chloride in significant quantities for several hours after the unit is first fired.

Safety Concerns - Finally, safety concerns prevent operators from attempting to reduce the startup period. Reductions in the amount of time required to warm the boiler system up could be realized by increasing the ramp-rate of adding fuel to the unit. Although a boiler could potentially be brought from first flame to full load in a matter of minutes, decreasing the warm-up period from OEM recommendations risks severe metallurgical stresses due to rapid changes in temperature and wide variances in temperatures across the boiler and duct parts. Immediate failures could occur if inconsistent heating caused tears or ruptures in support steel or heat transfer surfaces, posing considerable risk to personnel in the plant. Failure rates would also increase due to the considerable stresses introduced by rapid heating and cooling cycles, yielding failures at unpredictable times. OEM recommendations for startup times are closely followed across industry for these reasons.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Kevin M. Dempsey
Commenter Affiliation: American Iron and Steel Institute
Document Control Number: EPA-HQ-OAR-2002-0058-2998.1
Comment Excerpt Number: 26

Comment: EPA makes a mistake with regard to its proposal not to set a separate standard for periods of startup, shutdown, and malfunction. On the one hand, EPA asserts that “[t]he standards we are proposing are daily or monthly averages ... [t]hus, we are not establishing separate emission standards for these periods because startup and shutdown are part of their routine operations and, therefore, are already addressed by the standards.”14 On the other hand, EPA uses short-term performance test results to set the standards rather than the results of long-term CEMS monitoring. As a result, the emissions data on which the standards are based do not, in fact, reflect or adequately accommodate emissions from periods of startup, shutdown, or malfunction. To assure that startup, shutdown, and malfunction are appropriately accommodated, EPA must either assure that the data on which the standard is based include representative data from such periods or, alternatively, set a separate work practice standard to properly accommodate startup, shutdown, and malfunction.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Gary W. Kruger
Commenter Affiliation: Morton Salt
Document Control Number: EPA-HQ-OAR-2002-0058-2883.1
Comment Excerpt Number: 27

Comment: It must also be recognized that startups and shutdowns are often neither predictable nor routine. 75 FR at 33012. Industrial facilities, unlike electric utilities, typically operate a large number of smaller units of varying ages instead of operating a small number of very large units. When normal equipment failure rates such as tube leaks are multiplied across a large number of units, the total number of unit failures can be significantly larger at industrial facilities. It is not uncommon for unplanned outages to occur in clusters, such as when a given component, for example, an economizer might suffer a failure due to corrosion or erosion. Repairs may fix the failure at identified vulnerable areas nearby, but the root cause of the failure could be occurring in multiple areas that are not easily identified, resulting in additional failures in a short timeframe.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Gary W. Kruger
Commenter Affiliation: Morton Salt
Document Control Number: EPA-HQ-OAR-2002-0058-2883.1
Comment Excerpt Number: 28

Comment: EPA seeks to address the fact that units will not be able to comply with the proposed emissions standards by during startups and shutdowns by proposing extended daily or monthly

averaging periods. However, this assumption that longer averaging periods will provide a reasonable method to ensure compliance is flawed. Startup and shutdown periods vary in duration and intensity, a fact that can significantly impact actual emission profiles. Additionally, because unplanned outages are a reality in the operation of any boiler, industrial or utility, and because unplanned outages are by their nature unpredictable, unplanned shutdowns can and will cluster together. The calculation of a 30-day average fails to prevent deviations from emissions standards for multiple outages in the month following startup from a planned shutdown. A unit would be out of compliance because the rule as proposed includes no compliance protocol to address the fact that emissions performance during startups and shutdowns is not equivalent to emissions performance during steady-state operation.
Extended averaging periods are similarly inadequate to provide a reasonable method to demonstrate compliance with the CO standard, due to the inherent variability of CO in solid fuel boilers across the load range, but especially upon startup.

Response: See the preamble for response to how EPA adjusted CO emission limits and compliance mechanisms, and changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Bruce A. Steiner
Commenter Affiliation: American Coke and Coal Chemicals Institute
Document Control Number: EPA-HQ-OAR-2002-0058-2849.1
Comment Excerpt Number: 28

Comment: The Proposed Rule does not include a separate standard for startup and shutdown. This is a fundamental problem that, if not corrected, will cause the final standards to be unachievable by even well designed and operated boilers. As a result, EPA must include a separate standard for startup and shutdown in the final rule.
EPA explains in the preamble that, “Based upon continuous emission monitoring data, obtained as part of the information collection effort for the major source boiler and process heater rulemaking, which included periods of startup and shutdown, over long averaging periods, startups and shutdowns will not affect the achievability of the standards.” 75 FR at 31901. There are two fundamental problems with this justification for not including startup and shutdown standards in the rule.
First, EPA’s emissions database provides continuous emissions monitoring system (CEMS) data from several of the better performing sources. Contrary to EPA’s assertion in the preamble, these data show that daily average emissions should be expected to vary considerably on a day-to-day basis and that the variability spans the proposed levels of the standards. While it is difficult to discern the reasons for this variability based on the information provided in the database, there is little doubt that startups and shutdowns significantly contribute to the variable emissions performance of these units. Thus, the data indicate that EPA needs to include express accommodation for startups and shutdowns.
Second, basic scientific and engineering principles support the need for a separate standard for startup and shutdown. Particularly for CO emissions, combustion conditions will not be optimum during startup periods due to the generally low firing rate and the fact that the firing rate will be

ramped up over the startup period. Thus, a significant period of non-optimum firing conditions will result in CO emissions performance – even on a daily average basis – that will be markedly different than performance during normal operations. EPA's failure to acknowledge these basic technical and engineering principles renders the proposed standards arbitrary.
For these reasons, we believe that a separate standard for startup and shutdown is needed and is amply justified. We suggest that a work practice standard is most appropriate due to the lack of relevant data and the fact that an emission testing during startup is not technically and economically practicable. If EPA decides that a numeric standard is needed, the Agency should rely on the available long term data from the better performing boilers to establish a standard with a reasonably long averaging time (such as a 30-day rolling average), rather than the proposed 24-hour averaging time.

Response: See the preamble for response to how EPA adjusted CO emission limits and compliance mechanisms, and changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Gary W. Kruger
Commenter Affiliation: Morton Salt
Document Control Number: EPA-HQ-OAR-2002-0058-2883.1
Comment Excerpt Number: 29

Comment: Instead of relying on extended averaging periods, Morton Salt believes that EPA should instead provide additional provisions to ensure emissions are minimized during startups and shutdowns without unreasonably requiring sources to attempt to comply with steady-state emission standards. EPA should add provisions to require sources to develop and adhere to operating practices specific to the unit's design, fuel type, and OEM recommendations that will ensure emissions minimization without forcing owner/operators to choose between putting their equipment and personnel at risk versus failing to comply with this rule. Such an operating practice should be crafted to be flexible, given the wide variety of boiler sizes, types, vintages, and fuels fired, and should be developed by the source based on OEM recommendations.
General guidelines could include:
* Sequencing of equipment startups, per OEM recommendations;
* Startup time durations, per OEM recommendations, and
* Provisions to clearly define what constitutes online versus startup. This could be crafted to mean a percentage of the unit's maximum continuous rating, or steam temperature/pressure, etc.
EPA should use operating practices during startup and shutdown to include general content relative to specific startup and shutdown sequences and time limits pending meeting emissions limits. Alternatively, if EPA uses a startup/shutdown standard, EPA should establish a broader averaging period that accounts for a wide range of emissions from startup and shutdown.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Sarah E. Amick
Commenter Affiliation: Rubber Manufacturers Association
Document Control Number: EPA-HQ-OAR-2002-0058-2941.1
Comment Excerpt Number: 29

Comment: In addition to the unique operating characteristics of limited use boilers, there are practical reasons for creating a limited use subcategory as well. As noted by Judge Williams in Sierra Club v. EPA, "Section 112(d)(1) authorizes the Administrator to 'distinguish among classes, types, and sizes of sources within a category or subcategory' . . . . [O]ne legitimate basis for creating additional subcategories must be the interest of keeping the relation between 'achieved' and 'achievable' in accord with common sense and the reasonable meaning of the statute. Sierra Club v. EPA, 479 F.3d 875, 884-85 (D.C. Cir. 2007) (Williams, J., concurring).

Without subcategorization for limited use boilers, these infrequently operated units would need to comply with the same emission limits set by units that operate on a continuous bases. As noted above, "combustion units operate most efficiently when operated at or near their design capacity. The combustion efficiency tends to decrease as the unit's load (steam production) decreases." National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters, 75 Fed.Reg. at 32023. Limited use boilers would therefore be operating for a significantly greater percentage of their time during periods of inefficient operation.

While EPA has already attempted to address this problem through the current MACT floor analysis by addressing the reduced efficiency of load-following units through allowances for variability,[See MACT Floor Analysis (2010) for the Industrial, Commercial, and Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants – Major Source at 9-10 (April 2010).] this problem is further amplified for limited use boilers, which EPA did not address in its MACT floor analysis, due to EPA's decision to include periods of startup and shutdown in determining compliance with MACT. As found by EPA, this was justified because "the standards that we are proposing are daily or monthly averages. Continuous emission monitoring data obtained from best performing units, and used in establishing the standards, include periods of startup and shutdown. Boilers, especially solid fuel-fired boilers, do not normally startup and shutdown more the [sic] once per day. Thus, we are not establishing a separate emission standard for these periods because startup and shutdown are part of their routine operations and, therefore, are already addressed by the standards." Id. at 32013.[28 Continuous emission monitoring data is not available for all pollutants in the database. To the extent that emission limits are based on stack test data that does not consider SSM events, emission information based on an operator's knowledge and engineering calculations can be used to incorporate SSM variability into the MACT Floor analysis.]

Moreover, EPA found that "[p]eriods of startup, normal operations, and shutdown are all predictable and routine aspects of a source's operation." Id. Neither of these findings reasonably applies to emergency or backup boilers. First, as discussed above, emergency and backup boilers cannot practically make measurements over a monthly average given their limited utilization. Second, emergency and backup uses are by definition neither predictable nor routine.

By their very nature, emergency and backup boilers must spend a larger percentage of time in startup, shutdown, or other reduced-efficiency operating conditions than either base-loaded or load-following units. EPA should not require limited use boilers to comply with standards set by the best operated of these more efficient units.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Gary W. Kruger
Commenter Affiliation: Morton Salt
Document Control Number: EPA-HQ-OAR-2002-0058-2883.1
Comment Excerpt Number: 30

Comment: Malfunctions Cannot Be Avoided - Even By Top Performers - and EPA Should Therefore Include the Use of Malfunction Plans.
EPA states in the proposed rule that if a source fails to comply with the applicable standard due to a malfunction event, EPA would determine an appropriate response. 75 FR 32,013. Many large sources have been required to submit Standard Operation and Malfunction Procedures under Title V concerning time limitations of malfunctions that impact emissions. These procedures were based on not exceeding monthly averages in the permit. Furthermore, the definition for malfunctions appears to be inappropriate considering that many malfunctions occur due to component failure and have nothing to do with poor maintenance or careless operation as defined in 40 C.F.R. 63.2.
Congress acknowledged that malfunctions cannot be prevented, and provisions allow for such occurrences. EPA also acknowledged that malfunctions cannot be prevented, even by top performers, and therefore defined a malfunction in the preamble of the proposed rule as a sudden, infrequent, and not reasonably preventable failure. Because EPA considered it difficult to set a standard for malfunction periods, EPA required all sources to comply with standards established for steady-state operation during periods of malfunction. This approach is unreasonable and inappropriately failed to include provisions that take into account the unpredictable nature of malfunctions, and that malfunctions occur to all units including top performers.

EPA should include additional provisions to accommodate the unpredictable and unavoidable malfunctions that both Congress and EPA acknowledged would occur. EPA should adopt a work practice of requiring malfunction plans to address potential equipment failures, provide troubleshooting and corrective actions, and other reasonable measures to minimize the duration of malfunctions and minimize emissions during unavoidable malfunctions. Using the plan and documenting actions in accordance with the plan would then constitute minimizing emissions via the general duty clause.

Response: See the preamble for achievability of limits and changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Sarah E. Amick
Commenter Affiliation: Rubber Manufacturers Association
Document Control Number: EPA-HQ-OAR-2002-0058-2941.1
Comment Excerpt Number: 32

Comment: EPA is proposing that boilers and process heaters with heat input capacities greater or equal to 100 MMBtu/hr "demonstrate that average CO emissions, on a 30-day rolling average, are at or below the proposed CO limit." National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters, 75 Fed.Reg. at 32034. This averaging period is essential to accommodating expected data variability, including SSM events. See, e.g. National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters; Final Rule, 69 Fed.Reg. at 5521. See Response to Public Comments on Proposed Industrial, Commercial, and Institutional Boilers and Process Heaters NESHAP at 102 (rejecting a 24-hour averaging period because a 30-day rolling average "accounts for the variability in fuel characteristics (e.g., moisture, Btu content, mixture) that occur for solid fuel-fired boilers and process heaters"). Without the ability to test for 30 continuous days or thereabouts, a limited use boiler could not reasonably be expected to meet the same emission limits due to their reduced ability to accommodate data variability and operators cannot adequately determine compliance with numeric emission limits.

The result would be a marked inability to practically measure emissions without operating these units for significant periods of time for the sole purpose of conducting emissions testing. As with the recently regulated emergency CI RICE, this would result in a new increase in emissions through the very effort to control emissions from these units. See National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines, 75 Fed.Reg. at 9655-56. Work practices are therefore the most feasible control for limited use boilers and should be adopted in the new rule.

Response: See the preamble for response to how EPA adjusted CO emission limits and compliance mechanisms, and changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Douglas J. Van Pelt
Commenter Affiliation: ExxonMobil
Document Control Number: EPA-HQ-OAR-2002-0058-2968.1
Comment Excerpt Number: 32

Comment: EPA should apply work practice standards during periods of startup, shutdown, and malfunctions to appropriately recognize the operating and emission differences during these periods.

It is extraordinarily difficult if not impossible for boilers or process heaters to meet the proposed limits during startup (typically extended periods during which heating is done slowly to prevent damaging the heater) and, in some cases (e.g., when decoking or soot blowing is necessary) during shutdown.

EPA's failure to provide specific standards applicable to startup, shutdown, and malfunction (SSM) periods in the proposed Boilers and Process Heaters MACT is contrary to the statute's requirement that the standards established under section 112(d) be "achievable." See 42 U.S.C. section 7412(d)(2). Furthermore, EPA's claims that the proposed standards reflect startup and shutdown periods are not supported by the record. Because EPA has no data to support the application of the proposed emission limits during SSM, EPA should use its authority under section 112(h) to set work practice standards applicable during SSM.

To address the decision in Sierra Club v. EPA, 551 F.3d 1019 (D.C. Cir. 2008), cert. denied, 2010 U.S. LEXIS 2265(2010), which vacated the exemption in 40 C.F.R. section 63.6(f)(1) and (h)(1) for SSM periods, EPA proposes emissions standards in the Boilers and Process Heaters MACT that apply at all times, including periods of SSM. While the D.C. Circuit has ruled that sources cannot be exempt from complying with MACT standards, the court noted that Congress recognized in some instances that it may not be feasible to prescribe or enforce an emission standard under section 112. See id. at 1028. In such cases, section 112(h) "work practices" or "operational" standards may be available. Id.

The D.C. Circuit also has recognized that standards based on what sources achieve must account for the limitations inherent in the technology used to reduce emissions. For example, in a case reviewing NSPS under section 111 of the CAA, Portland Cement Ass'n v. Ruckelshaus, 486 F.2d 375, 398 (D.C. Cir. 1973), the court acknowledged that "'startup' and 'upset' conditions due to plant or emission device malfunction, is an inescapable aspect of industrial life and that allowance must be made for such factors in the standards that are promulgated." Id. at 399; see National Lime Ass'n v. EPA, 627 F.2d 416, 431 n.46 (D.C. Cir. 1980) (noting that "a uniform standard must be capable of being met under most adverse conditions which can reasonably be expected to recur"). The D.C. Circuit acknowledged this same principle when reviewing emission standards for new sources in the medical waste incinerator rule under section 129 in Sierra Club v. EPA, 167 F.3d 658 (D.C. Cir. 1999). In that case, while the court did not find the record sufficient to support EPA's approach for new sources, the D.C. Circuit did not object to a standard-setting approach which would account for the performance of technology under the "worst reasonably foreseeable circumstances." See id. at 665. Furthermore, the D.C. Circuit reiterated the principle in National Lime that "where a statute requires that a standard be 'achievable,' it must be achievable 'under the most adverse circumstances which can reasonably be expected to recur.'" Id. at 665 (citing National Lime Ass'n v. EPA, 627 F.2d 416, 431 n.46 (D.C. Cir. 1980)). EPA's MACT floor-setting approach in the proposed Boilers and Process Heaters MACT ignores these longstanding principles by applying the standards at all times, including SSM.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Douglas J. Van Pelt
Commenter Affiliation: ExxonMobil
Document Control Number: EPA-HQ-OAR-2002-0058-2968.1
Comment Excerpt Number: 33

Comment: EPA's proposal mischaracterizes the role of startup and shutdown data play in EPA's floor-setting process. EPA claims that the agency considered startup and shutdown periods when setting the floors because CEMS data, relied on by EPA in "establishing the standards," included data from those periods. 75 Fed. Reg. at 32,013. Despite this claim, however, EPA does not rely on the CEMS data when setting the floors for boilers and process heaters. To the contrary, as indicated by the ERG memorandum in the docket, EPA uses test run data collected through the ICR phase II testing process, which reflect normal operating conditions, to set the proposed floors. See Memorandum from A. Singelton, ERG, to J. Eddinger, U.S. EPA, MACT Floor Analysis (2010) for the Industrial, Commercial, and Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants – Major Source at 3 (April 2010). Thus, according to EPA's own docket materials, the data used to set the proposed floors fail to account for the dynamic conditions and variable emissions occurring during startup and shutdown episodes. Furthermore, as the ERG memorandum makes abundantly clear, EPA's approach does not make use of the CEMs data (with the startup and shutdown information) in its variability analysis where it would be the most helpful in reflecting real world fluctuations in emissions. Id.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Douglas J. Van Pelt
Commenter Affiliation: ExxonMobil
Document Control Number: EPA-HQ-OAR-2002-0058-2968.1
Comment Excerpt Number: 34

Comment: Given the lack of and difficulty collecting data for startup and shutdown emissions information, it is appropriate for EPA to set work practices for these events for boilers and process heaters. Section 112(h) allows EPA to set work practice standards for situations where "it is not feasible in the judgment of the Administrator to prescribe or enforce an emission standard," defined as any situation where "the application of measurement methodology to a particular class of sources is not practicable due to technological and economic limitations." CAA section 112(h)(1)-(2); 42 U.S.C. section 7412(h)(1)(-2). Gathering data from startup and shutdown periods would be challenging given the brief nature of these periods as well as the need to define the exact time period for what is considered "startup" and/or "shutdown." Furthermore, a work practices approach for these periods would satisfy both the statute's requirement that MACT standards be "achievable" and the requirement that there be a MACT standard applicable at all times.

A work practices approach for these periods also would be consistent with EPA's recently promulgated MACT standards for compression ignition reciprocating internal combustion engines (CI-RICE). See National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines, Final Rule, 75 Fed. Reg. 9648 (Mar. 3, 2010). EPA finalized work practice standards for startup because the agency determined that it was "not feasible to finalize numerical emission standards that would apply during startup because the application of measurement methodology to this operation is not practicable due to technological and economic limitations." Id. at 9656. According to EPA, applicable test methods that would be needed to measure during these events "do not respond adequately to the relatively short term and highly variable exhaust gas characteristics occurring during these periods." Id. at 9665. Furthermore, EPA determined that the cost for testing all the engines affected by the rule to get the necessary data could be more than $1 billion. See id. Startup and shutdown periods for boilers encounter similar testing challenges and costs.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Douglas J. Van Pelt
Commenter Affiliation: ExxonMobil
Document Control Number: EPA-HQ-OAR-2002-0058-2968.1
Comment Excerpt Number: 35

Comment: EPA should set work practice standards to apply to malfunction periods. EPA acknowledges in the preamble to the proposed rule that it is "impracticable" to take periods of malfunctions into account when setting emissions standards given the "myriad different types of malfunctions that can occur across all sources in the category" and that "malfunctions can vary in frequency, degree, and duration, further complicating" the standard setting process. 75 Fed. Reg. at 32,013. Section 112(h) work practice standards, therefore, are well-suited to address malfunction periods and the complexities and challenges surrounding collecting data and establishing numerical standards for those events. Emission testing for malfunctions would be near impossible to conduct given the sporadic and unpredictable nature of the events.

With respect to malfunctions, EPA argues in the preamble to the proposed Boiler MACT that these periods should not be considered a "distinct operating mode" and uses this to justify not factoring these emissions into the proposed MACT standards. Considering that EPA's proposed MACT standards are supposed to apply at all times, the implication is that periods of malfunction also are covered by the MACT standards that apply during normal operations. This directly conflicts with the statutory requirement that the MACT standard be "achievable."

Given that the floor data does not consider malfunctions and that the statute requires that the MACT standard be "achievable," EPA should set work practice requirements to address periods of malfunctions as well. Section 112(h) allows EPA to set work practice standards for situations where "it is not feasible in the judgment of the Administrator to prescribe or enforce an emission standard . . . .” Similar to startup and shutdown, malfunctions fit with the situations described in the definition of “not feasible to prescribe or enforce an emission standard” as any situation where “the application of measurement methodology to a particular class of sources is not practicable due to technological and economic limitations.” Emission testing for malfunctions would be near impossible to conduct given the sporadic and unpredictable nature of the events. EPA acknowledges in the preamble to the proposed boiler rule that it is “impracticable” to take periods of malfunctions into account when setting emissions standards given the “myriad different types of malfunctions that can occur across all sources in the category” and that “malfunctions can vary in frequency, degree, and duration, further complicating” the standard setting process 75 Fed. Reg. at 32,013. Section 112(h) work practice standards, therefore, are well-suited to address malfunction periods and the complexities and challenges surrounding collecting data and establishing numerical standards for those events.

Response: See the preamble for achievability of limits and changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: David M. Kiser
Commenter Affiliation: International Paper Company
Document Control Number: EPA-HQ-OAR-2002-0058-2777.1
Comment Excerpt Number: 39

Comment: International Paper supports the fact that facilities do not have to develop and implement a Startup, Shutdown, and Malfunction (SSM) Plan nor submit periodic and immediate SSM reports.

SSM plans, Periodic SSM reports and Immediate SSM reports are no longer required per Table 10 of the proposed rule due to the SSM vacatur. EPA specifically requested comment on this point (75 FR 32012). International Paper agrees that no SSM plans or SSM recordkeeping and reporting provisions are warranted. If the limits are to apply at all times, however, as previously stated the proposed MACT limits do not account for SSM and therefore the standards should not apply during SSM periods. Instead, EPA should consider work practice standards during periods of SSM, as further detailed in AF&PA’s comments.

Response: See the preamble for response changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Don Grimm
Commenter Affiliation: Hood Industries, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2352
Comment Excerpt Number: 8

Comment: EPA makes a similar mistake with regard to its proposal not to set a separate standard for periods of startup, shutdown, and malfunction. On the one hand, EPA asserts that "[t]he standards we are proposing are daily or monthly averages … [t]hus, we are not establishing separate emission standards for these periods because startup and shutdown are part of their routine operations and, therefore, are already addressed by the standards." On the other hand, EPA uses short term performance test results to set the standards rather than the results of long-term CEMS monitoring. As a result, the emissions data on which the standards are based do not, in fact, reflect or adequately accommodate emissions from periods of startup, shutdown, or malfunction.

Response: See the preamble for response to how EPA adjusted CO emission limits and compliance mechanisms, and changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: John Williams
Commenter Affiliation: Maine Pulp and Paper Association
Document Control Number: EPA-HQ-OAR-2002-0058-1913.1
Comment Excerpt Number: 11

Comment: Startup, Shutdown, Malfunction. Under the proposed rule, there are no exemptions for startups, shutdowns or malfunctions (SSMs). EPA must recognize that the boilers at Maine Mills (and generally in the industry) do not run at steady state and that the proposed standards cannot be met while starting up and shutting down boilers. Startup, shutdowns and malfunctions should be exempt or the standards should be set for long-term averages that take into account the variations seen in SSM events.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Kerry Flick
Commenter Affiliation: Metso Power
Document Control Number: EPA-HQ-OAR-2002-0058-2388.1
Comment Excerpt Number: 7

Comment: Startup periods are not predictable and should not be included in the emissions averaging period. We recommend that startup periods be treated outside the averaging period similar to "periods of malfunction" (CAA section 112(d)).

The combustion of biomass has its challenges. Biomass has a low calorific value and high moisture content when compared to fossil fuels. Biomass characteristics can vary significantly based on a number of factors, including species, geographic origin, and time of year. Thus, there is variability in biomass that is not inherent to the combustion of fossil fuels. This variability along with the extreme dynamics associated with startups of a biomass fired boiler make it unreasonable to include them in the emissions compliance averaging period. The proposed ruling states that “Periods of startup, normal operations, and shutdown are all predictable and routine aspects of a source’s operation.” We have not found this to be the case in practice when it comes to biomass combustion. The variability in biomass makes it difficult to standardize an optimized mode of operation on a consistent basis, particularly during startup conditions. Thus, emission control during startup is anything but predictable and consistent. The source data supports this. The data presented for CO emissions fluctuate significantly during the performance testing period. Metso believes that no technology is commercially available, including oxidation catalysts, to control emissions of CO during startup or shutdown to the degree that would be required to satisfy the proposed rulings. These variations are further complicated by the fact that many units are not based-loaded and must deal with fluctuations in load that will create transient conditions, even during normal operation. This can result in frequent operating instabilities lasting several hours. compounding the unpredictable nature of biomass combustion and the resulting emissions.

Response: See the preamble for response to how EPA adjusted CO emission limits and compliance mechanisms, and changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: James P. Brooks
Commenter Affiliation: Maine Department of Environmental Protection, Bureau of Air Quality
Document Control Number: EPA-HQ-OAR-2002-0058-2746.1
Comment Excerpt Number: 2

Comment: EPA should include provisions for start-ups and shutdowns. Wood and multi-fueled fired boilers produce large CO variations during startups as the boilers heat up. Start-up can take up to 14 hours for some units. Shutdowns can also result in significant CO variability.

Response: See the preamble for response to how EPA adjusted CO emission limits and compliance mechanisms, and changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Jack Carter
Commenter Affiliation: Weyerhaeuser Company
Document Control Number: EPA-HQ-OAR-2002-0058-2797.1
Comment Excerpt Number: 4

Comment: EPA does not provide achievable limits or an alternative for a work practice for boiler start-ups, shutdowns or malfunctions (i.e., during “SSM” events). For example, during biomass boiler start-ups when temperatures are low and boiler load rate is low, CO emissions also are elevated; as the trade group comments note, this is in part due to elevated oxygen levels during start-up, which translate to very high O2-adjusted CO emission rates that are in the form required for comparison to the limit.

Response: See the preamble for response to how EPA adjusted CO emission limits and compliance mechanisms, and changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Robert Klemans
Commenter Affiliation: Florida Electric Power Coordinating Group Environmental Committee
Document Control Number: EPA-HQ-OAR-2002-0058-2733.1
Comment Excerpt Number: 5

Comment: EPA Should Not Treat HAP Emissions During Startup and Shutdown the Same as HAP Emissions During Normal Operation. The IB ICR did not require any testing during start-up, shutdown and malfunction events. Without emissions data during these periods, EPA has no factual basis for concluding that the best performing units can achieve the proposed MACT limits during start-up, shutdown and malfunction events. Operations during boiler startups are different than normal plant operations. Certain plant components must be started in a specific sequence in order to ensure that steady state operations can be achieved. During start-up, not all pieces of control equipment will be operating at peak efficiency. The FCG urges EPA to exempt these events based on the lack of data availability and its unrestricted operational control. In addition, FCG believes that startup, shutdown and malfunction events should be excluded from all emission averaging requirements in the IB MACT proposal. These events were not included in the ICR data gathering used to develop the emission standards, thus many of the proposed standards will be impossible to meet if these periods are included in the averaging periods.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Mark Denzler
Commenter Affiliation: Illinois Manufacturers' Association
Document Control Number: EPA-HQ-OAR-2002-0058-2635.1
Comment Excerpt Number: 7

Comment: Startup, Shutdown, and Malfunction Requirements Are Unrealistic. The EPA proposal specifies that the proposed emission limits apply during periods of startup, shutdown, and malfunction. In support of this proposal, EPA states that startup and shutdown emissions are equivalent to normal operation emissions based on continuous emission monitoring data obtained from best performing units that included periods of startup and shutdown. However, the test data does not show a sufficiently representative sampling of startup, shutdown, and malfunction conditions that represent their duration and variety of characteristics. By considering these periods to be part of "routine operations" EPA ignored the circumstances that justify the establishment of work practices or emission limits that would apply in such situations.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Jay C. Moon
Commenter Affiliation: Mississippi Manufacturers Association
Document Control Number: EPA-HQ-OAR-2002-0058-2690
Comment Excerpt Number: 10

Comment: EPA's analysis failed to properly address the variability of the data, as well as emissions associated with startup, shutdown and malfunction. Thus, EPA's proposed limits do not appropriately address the variability in emissions of various HAPs.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Lisa Beal
Commenter Affiliation: Interstate Natural Gas Association of America
Document Control Number: EPA-HQ-OAR-2002-0058-2756.1
Comment Excerpt Number: 12

Comment: EPA should clarify that startup, shutdown and malfunction plans and associated reporting are not required.

In Table 9 of the proposed rule, items 1(d) and 2 delineate requirements regarding startup, shutdown, and malfunction (SSM) plans and reporting. However, EPA indicates it is changing SSM requirements in response to recent Court decisions, and multiple citations in Table 10 of the proposed rule indicate that SSM plans and associated reporting are not required. These two tables are contradictory. Items 1(d) and 2 from Table 9 should be deleted.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Robert R. Scott
Commenter Affiliation: New Hampshire Department of Environmental Services, Air Resources Division
Document Control Number: EPA-HQ-OAR-2002-0058-2734.1

Comment Excerpt Number: 13

Comment: Steady State vs. Startup and Shutdown Scenarios
There is significant variation in the amount and duration of startup, shutdown and malfunction (SSM) emissions for various fuels. NIIDES anticipates that variations in SSM emissions would be greater for boilers firing solid fuels such as biomass, than for boilers firing liquid fuels such as heating oil. NHDES recommends that EPA consider setting 30-day averaging times for solid fuel boilers. In order to refine both the emission limits and averaging times, EPA should collect SSM data from CEMs installed at the facilities previously included in the MACT ICR. In addition, EPA should use portable analyzers to evaluate SSM emissions at smaller boilers in the ICR that do not have CEMs concurrently during future compliance testing. This should give EPA sufficient information within five years from promulgation of the regulation to develop appropriate limits and averaging times for SSM emissions.

Response: See the preamble for response to how EPA adjusted CO emission limits and compliance mechanisms, and changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: James P. Brooks
Commenter Affiliation: Maine Department of Environmental Protection, Bureau of Air Quality
Document Control Number: EPA-HQ-OAR-2002-0058-2746.1
Comment Excerpt Number: 14

Comment: While the Maine DEP recognizes that the courts decreed that emission standards established under the Clean Air Act must apply at all times, EPA must still consider the practical limitations of implementing this directive. In reality, during periods of startup and shutdown, all types of boilers emit more pollutants than during steady state operations. This is particularly true for biomass boilers, where the fuel is introduced onto the combustion chamber more gradually during start up and ceases combustion more gradually than liquid or gaseous fuels. Maine's experience is that the amount of time to reach the desired steady state for minimizing emissions depends on a number of factors such as the design of the system, its size, and the type of fuel that is combusted. The Maine DEP also recognizes that insufficient data is currently available to establish alternative emission standards for start-up and shutdown period. Therefore, we recommend that EPA require facilities to develop and implement plans to minimize the amount of time for startup and shut-downs and to minimize the amount of pollutants emitted during these periods. Accompanying emission standards with long averaging periods will ensure that overall emissions from affected units are minimized.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Jack Carter

Commenter Affiliation: Weyerhaeuser Company
Document Control Number: EPA-HQ-OAR-2002-0058-2797.1
Comment Excerpt Number: 16

Comment: EPA has chosen to assume for the proposed rule that emissions during SSM events are either (a) already incorporated into the emission limits they proposed based on a view that at least some of the stack test data in the database adequately represent such periods, or (b) the averaging periods EPA proposes provide sufficient room to smooth out emission spikes during those events so that compliance can be planned and engineered.

Based on our experience with boiler emissions during SSM events, we believe EPA's assumptions will prove inadequate in many cases, putting our sources at compliance risk for events that EPA failed to adequately consider in the MACT floors. We refer EPA to the very extensive technical discussions and quantitative proofs contained in the trade group comments reaching the same conclusion. Those comments demonstrate how such events are not adequately included in the database nor are existing combustion units capable of meeting the emission limits, especially for CO and PM, even when longer averaging periods are provided. For example, boiler start-up conditions typically produce elevated CO emissions that may exceed the limits even for "best performers" that are subject to a 30-day averaging period for compliance (i.e., when a CO CEMS is required for boilers of 100 mmBtu or more). At some of our wood products mills biomass boilers are currently operated on a four or five day schedule, so start-ups and shutdowns occur twice a week, making this a routine concern.

As a remedy, we encourage EPA to consider establishing work practices to address emissions during these SSM periods, but urge EPA while doing so to take care not to create redundant new regulatory burdens (i.e., either work in concert with or exempt from, the current Part 63 General Provisions that address the minimization of emissions consistent with safety and good combustion practices). We refer EPA to the AWC and AF&PA comments for detailed discussion of the legal requirement for addressing SSM periods so that the standards established under CAA 112(d) are "achievable." In the longer term EPA could collect the data to ensure that such events are truly represented in the database before establishing emission limits including SSM periods.

Response: See the preamble for response to how EPA adjusted CO emission limits and compliance mechanisms, and changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Arthur N. Marin
Commenter Affiliation: NESCAUM
Document Control Number: EPA-HQ-OAR-2002-0058-2893.1
Comment Excerpt Number: 25

Comment: EPA proposes to regulate emissions of HAPs from boilers during all phases of operations, including startup, shutdown, and malfunction (SSM) periods. We are unsure how EPA has accounted for these emissions within the proposed emission limits, as the current data do not include such emission measurements. Furthermore, there is significant variation in the amount and duration of SSM emissions for various fuels and sizes of boilers. For example, we anticipate that variation in SSM emissions would be greater when using boilers firing solid fuels, such as biomass, than with boilers firing liquid fuels such as heating oil. NESCAUM recommends that EPA use facilities regulated under this effort to collect SSM emissions data and then revisit this issue no later than five years from promulgation to develop appropriate limits for SSM emissions. Facilities that measure emissions with CEMS could provide the basis for developing emission limits for SSM periods. In addition, EPA should examine how to evaluate SSM emissions at smaller boilers that do not have CEMS, and how those facilities could evaluate those emissions during compliance testing.

Response: See the preamble for response to how EPA adjusted CO emission limits and compliance mechanisms, and changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Stephen R. Gossett
Commenter Affiliation: Eastman Chemical Company
Document Control Number: EPA-HQ-OAR-2002-0058-3137.1
Comment Excerpt Number: 41

Comment: EPA has not properly accounted for startup, shutdown, and malfunction conditions in the proposed emission standards.

EPA states that it obtained CEMS data from best performing units and used this data in establishing the standards. EPA further states that these periods are predictable and routine and it believes it is appropriate to have the same standards apply during startup and shutdown as applied to normal operation.

EPA has not established in the record that these statements and conclusions are true. The MACT floor standards were derived entirely from CO performance test (3-runs) data. While EPA did attempt to address variability by gathering 30 days of CO CEMS data from five boilers, it did not utilize this data other than to conclude that only the two biomass boilers showed an inverse relationship of CO to boiler load (see page 9 of the MACT floor memorandum) and to conclude that the statistical methodology using solely performance test data was appropriate.

Eastman notes that not all these data sets include periods of startup. In the stoker coal subcategory, the unit at DuPont in West Virginia did not note any periods of SSM in the CO Monitoring Template. Further, EPA's graph of the CO CEMS data plotted vs boiler load for the Phillip Morris boiler in Virginia (the only pulverized coal boiler with CEMS data in EPA's dataset) (see Appendix B-1 of the MACT floor memorandum) is wrong (it appears to plot the Excel row number vs. CO) and does not include data from boiler load below 100 mmBtu/hr. Included in Figure 2 of the submittal is the correct graph of this information. This boiler went through three startups during the 30 day period and the graph clearly shows elevated CO during low load periods and shows an inverse relationship of CO and boiler load. The average CO concentrations during periods of only “normal” operations was 35 ppm whereas the average CO concentrations during all periods (normal, shutdown, startup) was 27 ppm.

Response: See the preamble for response to how EPA adjusted CO emission limits and compliance mechanisms, and changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Stephen R. Gossett
Commenter Affiliation: Eastman Chemical Company
Document Control Number: EPA-HQ-OAR-2002-0058-3137.1
Comment Excerpt Number: 44

Comment: For the coal subcategory, EPA has not correctly assessed the impact of startups and shutdowns on 30 day rolling average CO concentrations. In the case of the stoker coal subcategory, no data from startups and shutdowns were included in EPA’s analysis. In the case of the pulverized coal subcategory, EPA’s analysis erroneously excluded startup periods from the one unit which has CEMS data. Additional data must be gathered before EPA can conclude that a standard based solely on 3-run performance tests can be met by the top performers using a 30 day rolling compliance period.

Response: See the preamble for response to how EPA adjusted CO emission limits and compliance mechanisms, and changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Stephen R. Gossett
Commenter Affiliation: Eastman Chemical Company
Document Control Number: EPA-HQ-OAR-2002-0058-3137.1
Comment Excerpt Number: 45

Comment: EPA has not addressed the PM standard as to whether or not the proposed standard is achievable by the top performers during SSMs. Since periodic stack gas performance tests do not include periods of SSM, most units will have no data upon which to determine if they are complying with the emission standard at all times. However, certain boilers over 250 mmBtu/hr heat input rating would have PM CEMS to demonstrate compliance with the PM standard on a daily average basis. EPA has not collected data to determine if the top performers can achieve the emission standard during SSMs on a daily average basis. As discussed below, there are cases where boilers can have higher emissions during a startup period than during steady-state operation:

Fabric Filters (FF) installed for particulate matter (PM) control are designed to operate at steady state conditions where the flue gas temperature is well above the dewpoint temperature. If flue gas at or below the dewpoint temperature is passed through a FF, a phenomenon called "blinding" of the bags will occur. "Blinding" of the bags occurs when ash, either already embedded in a bag that has been previously in service, or ash entrained in the flue gas, is wetted and embeds itself into the fibers of the bags in such a manner as to permanently restrict the flow of flue gas. Bags that have been "blinded" are unable to pass their rated volumetric flow of flue gas, resulting in boiler derating, and poor PM removal, and are prone to sudden failure. Bags that have been badly "blinded" are not able to remain in service, and require an unplanned shutdown and replacement. As with any unplanned outage due to failure, the lead time and cost of replacement parts (several hundred or thousands of bags for a FF) is significant. Additionally, when gas at or below its dewpoint temperature is passed through a FF, the interior surface of the metal casing would be subject to widespread and aggressive corrosion. As an example of how significant this failure mode is viewed to be by OEM's, most boilers that have FF installed downstream of semi-dry scrubbers (e.g., Spray Dryer Absorbers, or SDAs) have elaborate control systems designed to limit how low the temperature of the flue gas entering the FF can go, specifically to protect the FF from blinding bags or incurring excessive damage due to corrosion.

Large utility boilers equipped with FF for particulate control typically have very large FFs, with multiple compartments, or multiple FFs each with multiple compartments. Such configurations allow the utility the option to designate one compartment as a "sacrificial compartment" during each startup and shutdown event. A "sacrificial compartment" is the one compartment which is designated to see flue gas that is very close to the dewpoint. The remaining compartments are only returned to service after the flue gas has reached a minimum temperature judged to be safely above the dewpoint. This limits the unit's risk of bag failures and corrosion damage to a single compartment. Smaller institutional, commercial and industrial boilers, by contrast, do not always have the luxury of very large FFs with many compartments, and thus cannot limit their risk of widespread bag failures and corrosion damage. In this regard, the industrial boiler community faces a technical challenge that is unique due to their smaller size.

EPA should include additional provisions in this rule to address PM compliance during startups and shutdowns for boilers equipped with FFs. Institutional, Commercial and Industrial boilers should be allowed to comply with a different standard during periods of startup and shutdown, or be allowed to develop startup and shutdown plans specific to the individual unit and its startup fuel(s) that control emissions without subjecting the equipment to recurring costly failures.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Britt S. Fleming
Commenter Affiliation: Auto Group
Document Control Number: EPA-HQ-OAR-2002-0058-2775.1
Comment Excerpt Number: 50

Comment: In § 63.7505(a) of the proposed Boiler MACT rule, sources would be subject to emission limits and operating limits at all times. [Footnote: See id. at 32,050.] This would mean that units using landfill gas would have to comply with the emission limits under any and all conditions. EPA's proposed approach to addressing startup, shutdown, and malfunction (SSM) periods for other gas units in the Boiler MACT is contrary to the statute's requirement that the standards established under section 112(d) be "achievable." [Footnote: See CAA 112(d)(2); 42 U.S.C. § 7412(d)(2).] Furthermore, EPA's claims that the MACT standards reflect startup and shutdown periods are not supported by the record.

To address the decision in Sierra Club v. EPA, [Footnote: 551 F.3d 1019 (D.C. Cir. 2008), cert. denied, 2010 U.S. LEXIS 2265(2010).] which vacated the exemption in 40 C.F.R. § 63.6(f)(1) and (h)(1) for SSM periods, EPA proposes emissions standards in the MACT for boilers and process heaters that apply at all times, including periods of SSM. EPA claims in the preamble that startup and shutdown periods were taken into consideration when setting the MACT standards. [Footnote: See 75 Fed. Reg. at 32,012-13.] According to the preamble, CEM data from the best performing units, which include startup and shutdown periods, are used to set the floor levels in the proposed rule. [Footnote: See 75 Fed. Reg. at 32,012-13.] EPA further notes that startup and shutdown are part of "routine operations" and are therefore "already addressed" in the MACT standards. While the Auto Group agrees with EPA that startup and shutdown are part of routine operations, these periods have not been adequately addressed by EPA's proposed emission limits or analyzed properly when setting the floors. As discussed below, work practices should be established to accommodate startup and shutdown periods.

With regard to malfunctions, however, EPA states that these periods should not be viewed as a "distinct operating mode," and thus, emissions from these periods do not need to be factored into developing the MACT floor levels. Moreover, EPA states that even if malfunctions were to be considered a distinct operating mode, it would be "impracticable to take malfunctions into account in setting CAA section 112(d) standards for major source boilers and process heaters" given that these episodes are by definition sudden and unexpected events which vary in degree, frequency, and duration. The Auto Group agrees that it would be impracticable to establish emission limits for malfunctions as they vary in degree, frequency and duration. As discussed in detail below, work practices also should be established to accommodate malfunction periods.

When setting standards in the early 1990's under CAA section 112(d), EPA used its New Source Performance Standards (NSPS) program as a model. The section 112 standards were acknowledged by EPA to be "essentially equivalent to [section 111] performance standards" and that "unpredicted and reasonably unavoidable failures of air pollution control systems" would occur. [Footnote: See 58 Fed. Reg. 42,760, 42,777 (Aug. 11, 1993).] To address this situation, EPA adopted a similar exemption to the one in the NSPS Program for SSM events and imposed a "general duty" to minimize emissions. Thus, EPA acknowledged, as early as 1993, that SSM events are not appropriate for inclusion in a MACT standard and that an alternative approach should be used to address these situations. While the D.C. Circuit has ruled that sources cannot be exempt from complying with MACT standards, the court noted that Congress recognized in some instances that it may not be feasible to prescribe or enforce an emission standard under section 112, and so section 112(h) "work practices" or "operational" standards are available in certain limited situations. [Footnoe: See Sierra Club v. EPA, 551 F.3d at 1028.]

The D.C. Circuit also has recognized that standards based on what sources achieve must account for the limitations inherent in the technology used to reduce emissions. For example, in a case reviewing NSPS under section 111 of the CAA, Portland Cement Ass'n v. Ruckelshaus, [Footnote: 486 F.2d 375, 398 (D.C. Cir. 1973).]the court acknowledged that "'startup' and 'upset' conditions due to plant or emission device malfunction, is an inescapable aspect of industrial life and that allowance must be made for such factors in the standards that are promulgated." [Footnote: Portland Cement Ass'n v. Ruckelshaus, 486 F.2d at 399.] Furthermore, in National Lime Ass'n v. EPA, [Footnote: 627 F.2d 416 (D.C. Cir. 1980).] the court noted that "a uniform standard must be capable of being met under most adverse conditions which can reasonably be expected to recur." [Footnote: National Lime Ass'n v. EPA, 627 F.2d at 431 n.46.] The D.C. Circuit acknowledged this same principle almost 20 years later when reviewing emission standards for new sources in the medical waste incinerator rule under section 129 in Sierra Club v. EPA. [Footnote: 167 F.3d 658 (D.C. Cir. 1999).] In that case, while the court did not find the record sufficient to support EPA's approach for new sources, the D.C. Circuit did not object to a standard-setting approach which would account for the performance of technology under the "worst reasonably foreseeable circumstances." [Footnote: Sierra Club v. EPA, 167 F.3d at 665.] Furthermore, the D.C. Circuit reiterated the principle in National Lime that "where a statute requires that a standard be 'achievable,' it must be achievable 'under the most adverse circumstances which can reasonably be expected to recur.'" [Footnote: Id. at 665 (citing National Lime Ass'n v. EPA, 627 F.2d 416, 431 n.46 (D.C. Cir. 1980)).]

EPA's MACT floor-setting approach in the proposed Boiler MACT ignores these longstanding principles and mischaracterizes the role startup and shutdown data play (or rather, does not play, as the case is here) in EPA's floor-setting process. As noted above, EPA claims that the agency considered startup and shutdown periods when setting the floors because CEMs data, relied on by EPA in "establishing the standards," included data from those periods. [Footnote: See 75 Fed. Reg. at 32,012.] Despite this claim, however, EPA does not rely on the CEMs data when setting the floors for boilers and process heaters. To the contrary, as indicated by the ERG memorandum in the docket, EPA uses test run data collected through the ICR phase II testing process, which reflect normal (often steady state) operating conditions, to set the proposed floors. [Footnote: See Memorandum from A. Singelton, ERG, to J. Eddinger, U.S. EPA, MACT Floor Analysis (2010) for the Industrial, Commercial, and Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants – Major Source at 3 (April 2010).] Thus, according to EPA's own docket materials, the data used to set the proposed floors fail to account for the dynamic conditions and variable emissions occurring during startup and shutdown episodes. Furthermore, as the ERG memorandum makes abundantly clear, EPA's approach does not make use of the CEMs data (with the startup and shutdown information) in its variability analysis. [Footnote: See Memorandum from A. Singelton, ERG, to J. Eddinger, U.S. EPA, MACT Floor Analysis (2010) for the Industrial, Commercial, and Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants – Major Source at 3 (April 2010).]

Response: See the preamble for achievability of limits and changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Britt S. Fleming

Commenter Affiliation: Auto Group
Document Control Number: EPA-HQ-OAR-2002-0058-2775.1
Comment Excerpt Number: 51

Comment: Even if EPA were to include the 30 day CEMs data in setting the emission limits for the Gas 2 subcategory, it is not clear that the 30 day CEMs data is representative of sources that experience frequent startup and shutdown events. For example, a facility that uses process steam and is only operating one shift per day may shutdown the boiler at the end of each shift to reduce operating expenses and conserve resources. If a source measures high CO emissions for a brief period of time during startup and shutdown of that unit, it may take several days—and perhaps a whole month—for the average to fall below the proposed limit. This effectively would compel the source to idle the boiler instead of shutting it down in order to ensure compliance with the very low emission limits. Such a result is contrary to common sense and conflicts with the goals of reducing fuel consumption and emissions.

Response: See the preamble for response to how EPA adjusted CO emission limits and compliance mechanisms, and changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Britt S. Fleming
Commenter Affiliation: Auto Group
Document Control Number: EPA-HQ-OAR-2002-0058-2775.1
Comment Excerpt Number: 52

Comment: In addition, CEMs are not an appropriate way to measure emissions during SSM events. Specifically, CEMs are certified using reference test methods that require near steady state operation. RATA testing requires near steady state operation for 21 minute intervals and is performed only after a boiler has reached normal operating conditions. The conditions that occur during SSM events are anything but steady state and therefore there would be no way to verify with a RATA test that the CEMs is operating properly.

From an economic perspective, the use of CEMs to measure emissions during SSM events is not feasible. First, facilities do not have CEMs on every boiler or process heater at a facility and, therefore, the equipment would need to be installed on multiple units at the affected facilities. The cost of installing a CEMs is considerable. One vendor estimate indicates that the total installed cost can range from $35,000-45,000 per unit. This includes the cost for the sample line, sample probe, rack, analyzers, data collection and engineering. In addition to these costs, there also are operating expenses for the equipment that can run from $24,000-$34,000 annually per CEMs. This amounts to a significant cost for an affected source for equipment that is not even demonstrated as an accurate way to measure during SSM events. Furthermore, for those CEMs that already are installed, EPA’s proposed emission limits would necessitate an additional range to monitor compliance. This would mean additional equipment would be needed just for this rule, which would require additional installation and operational costs as well for existing CEMs. Considering that a vast majority of facilities have multiple affected units, the use of CEMs is not economically feasible.

Response: See the preamble for response to how EPA adjusted CO emission limits and compliance mechanisms, and changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Britt S. Fleming
Commenter Affiliation: Auto Group
Document Control Number: EPA-HQ-OAR-2002-0058-2775.1
Comment Excerpt Number: 53

Comment: In light of the absence of startup and shutdown emissions information from the test run data relied on by EPA to set the proposed standards and the difficulty of collecting data from such brief operation periods, including data from CEMs, it is appropriate for EPA to set work practices for these events for boilers and process heaters. As discussed earlier, section 112(h) allows EPA to set work practice standards for situations where "it is not feasible in the judgment of the Administrator to prescribe or enforce an emission standard . . . ." [Footnote: CAA § 112(h)(1); 42 U.S.C. § 7412(h)(1).] Gathering data from startup and shutdown periods would be challenging given the brief nature of these periods as well as the need to define the exact time period for what is considered "startup" and/or "shutdown." Moreover, the definition of "not feasible to prescribe or enforce an emission standard" is defined in the CAA as any situation where "the application of measurement methodology to a particular class of sources is not practicable due to technological and economic limitations." [Footnote: CAA § 112(h)(2); 42 U.S.C. § 7412(h)(2).] Attempting to measure combustion emissions while the boiler (or process heater) is in a state of flux does not lead to reproducible or reliable data and is not economically feasible. Startup and shutdown episodes, therefore, fit with this definition and would justify the agency setting work practices to address emissions during these periods. Furthermore, a work practices approach for these periods would be in keeping with the statute's requirement that MACT standards be "achievable" as well as with the requirement that a MACT standard apply at all times.

A work practices approach for these periods also would be consistent with EPA's recently promulgated MACT standards for compression ignition reciprocating internal combustion engines (CI-RICE). [Footnote: See National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines, 75 Fed. Reg. 9648 (Mar. 3, 2010).] Based on comments received from stakeholders, EPA finalized work practice standards for startup because the agency determined that it was "not feasible to finalize numerical emission standards that would apply during startup because the application of measurement methodology to this operation is not practicable due to technological and economic limitations." [Footnote: See National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines, 75 Fed. Reg. at 9656. (Mar. 3, 2010).] According to EPA, applicable test methods that would be needed to measure during these events "do not respond adequately to the relatively short term and highly variable exhaust gas characteristics occurring during these periods." [Footnote: See National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines, 75 Fed. Reg. at 9665. (Mar. 3, 2010).] Furthermore, EPA determined that the cost for testing all the engines affected by the rule to get the necessary data could be more than $1 billion. [Footnote: See National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines, 75 Fed. Reg. 9648 (Mar. 3, 2010).] Startup and shutdown periods for boilers encounter similar testing challenges and costs. For these reasons, the Auto Group recommends that for startup and shutdown periods, EPA consider a work practices requirement similar to the approach used in the CI-RICE MACT noted above, that would limit these periods to three hours or require sources to comply with manufacturer specifications, if available.

Response: See the preamble for response to how EPA adjusted CO emission limits and compliance mechanisms, and changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Britt S. Fleming
Commenter Affiliation: Auto Group
Document Control Number: EPA-HQ-OAR-2002-0058-2775.1
Comment Excerpt Number: 54

Comment: With respect to malfunctions, as noted earlier, EPA argues in the preamble to the proposed Boiler MACT that these periods should not be considered a "distinct operating mode" and uses this to justify not factoring these emissions into the proposed MACT standards. Considering that EPA's proposed MACT standards are supposed to apply at all times, the implication is that periods of malfunction also are covered by the MACT standards that apply during normal operations. This directly conflicts with the statutory requirement that the MACT standard be "achievable."

Given that the floor data does not consider malfunctions and that the statute requires that the MACT standard be "achievable," EPA should set work practice requirements to address periods of malfunctions as well. As noted above, section 112(h) allows EPA to set work practice standards for situations where "it is not feasible in the judgment of the Administrator to prescribe or enforce an emission standard . . . ." Similar to startup and shutdown, malfunctions fit with the situations described in the definition of "not feasible to prescribe or enforce an emission standard" as any situation where "the application of measurement methodology to a particular class of sources is not practicable due to technological and economic limitations." Emission testing for malfunctions would be near impossible to conduct given the sporadic, short term, and unpredictable nature of the events. As noted earlier, EPA acknowledges in the preamble to the proposed Boiler MACT that it is "impracticable" to take periods of malfunctions into account when setting emissions standards given the "myriad different types of malfunctions that can occur across all sources in the category" and that "malfunctions can vary in frequency, degree, and duration, further complicating" the standard setting process. [Footnote: 75 Fed. Reg. at 32,013.] Section 112(h) work practice standards, therefore, are well-suited to address malfunction periods and the complexities and challenges surrounding collecting data and establishing numerical standards for those events.

For startups, boilers and process heaters need to be brought up to normal firing rates slowly, and three hours, as a default, is a sufficient period of time to ensure that the unit reaches the optimal firing rate without damaging the unit. With regard to malfunction periods, The Auto Group suggests that EPA require owners and operators to minimize emissions during malfunctions to the greatest extent practicable and follow safe operation practices.

Response: See the preamble for achievability of limits and changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 253

Comment: When setting standards in the early 1990's under CAA 112(d), EPA used its New Source Performance Standards (NSPS) program as a model. The section 112 standards were acknowledged by EPA to be "essentially equivalent to [section 111] performance standards" and that "unpredicted and reasonably unavoidable failures of air pollution control systems" would occur. 58 Fed. Reg. 42,760, 42,777 (Aug. 11, 1993). To address this situation, EPA adopted a similar exemption to the one in the NSPS Program for SSM events and imposed a "general duty" to minimize emissions. Thus, EPA acknowledged, as early as 1993, that SSM events are not appropriate for inclusion in a MACT standard and that an alternative approach should be used to address these situations. While the D.C. Circuit has ruled that sources cannot be exempt from complying with MACT standards, the court noted that Congress recognized in some instances that it may not be feasible to prescribe or enforce an emission standard under section 112, and so section 112(h) "work practices" or "operational" standards are available in certain situations. See Sierra Club v. EPA, 551 F.3d at 1028.
The D.C. Circuit also has recognized that standards based on what sources achieve must account for the limitations inherent in the technology used to reduce emissions. For example, in a case reviewing NSPS under section 111 of the CAA, Portland Cement Ass'n v. Ruckelshaus, 486 F.2d 375, 398 (D.C. Cir. 1973), the court acknowledged that "'startup' and 'upset' conditions due to plant or emission device malfunction, is an inescapable aspect of industrial life and that allowance must be made for such factors in the standards that are promulgated." Id. at 399. Furthermore, in National Lime Ass'n v. EPA, 627 F.2d 416 (D.C. Cir. 1980), the court noted that "a uniform standard must be capable of being met under most adverse conditions which can reasonably be expected to recur." Id. at 431 n.46. The D.C. Circuit acknowledged this same principle almost 20 years later when reviewing emission standards for new sources in the medical waste incinerator rule under section 129 in Sierra Club v. EPA, 167 F.3d 658 (D.C. Cir. 1999). In that case, while the court did not find the record sufficient to support EPA's approach for new sources, the D.C. Circuit did not object to a standard-setting approach which would account for the performance of technology under the "worst reasonably foreseeable circumstances." See id. at 665. Furthermore, the D.C. Circuit reiterated the principle in National Lime that "where a statute requires that a standard be 'achievable,' it must be achievable 'under

the most adverse circumstances which can reasonably be expected to recur.'" Id. at 665 (citing National Lime Ass'n v. EPA, 627 F.2d 416, 431 n.46 (D.C. Cir. 1980)).
EPA's MACT floor-setting approach in the Proposed Boiler MACT ignores these longstanding principles and mischaracterizes the role startup and shutdown data plays (or rather, does not play, as the case is here) in EPA's floor-setting process. As noted above, EPA claims that the agency considered startup and shutdown periods when setting the floors because CEMS data, relied on by EPA in "establishing the standards," included data from those periods. See Proposed Boiler MACT Rule at 75 FR 32012.

Response: See the preamble for response to how EPA adjusted CO emission limits and compliance mechanisms, and changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 255

Comment: The following data is a subset of the data available to EPA within the docket. These excerpts reflect start-up and shutdown CO data from two facilities. One is a coal fired unit and one is a wood fired unit. Both data sets provide EPA data during periods of start-up and shutdown. While the absolute values are different in both cases the data indicates that carbon monoxide levels are up to twenty times greater during such periods. This is due to the influence of oxygen levels. When fuel values are low, as during periods of start-up and shutdown, oxygen levels are higher, making the corrected pollutant concentrations much higher. Further, as noted in the data set, the raw pollutant levels are elevated due to unstable combustion. [See submittal for to graphs showing CO and O2 levels during startup and shutdonw at a coal-fired and wood-fired boiler.]

If EPA had examined these data in some detail, it would have recognized two important aspects of the startup and shutdown periods. First, during startup periods, the oxygen content of the flue gas is generally very high, resulting in high calculated concentrations of pollutants, when they are corrected to 3 or 7 percent oxygen. Second, during shutdown periods many types of boilers continue to emit pollutants for some time while the fuel feed rate has gone to zero. Thus, during those periods the pollutant emission rates when measured in terms of the heat input rate would contain a zero in the denominator and would equal infinity. Combining emissions during shutdown periods with all operating periods would mean an emission limit of infinity. Based on this ridiculous outcome, we recommend that EPA exclude periods of startup and shutdown from its numerical standards and replace them with work practice standards aimed at minimizing pollutant emissions.
It is apparent that EPA did not consider this data when it established the proposed standards. In each of the cases present above, the proposed standards would have been exceeded during a 30 day period simply due to a start-up and shutdown condition. We believe that EPA should strongly reconsider this information before finalizing a standard.

Response: See the preamble for response to how EPA adjusted CO emission limits and compliance mechanisms, and changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 256

Comment: Particulate matter is elevated during start-up or shutdown. Although data are not available in the data sets provided by EPA, the following hypothetical example demonstrates the effect. Using the above equation the following set of results can be calculated: [See submittal for table showing an increase in PM emissions (lb/mmBtu) when % O2 increases.]

In such situations it is very likely sources will exceed the proposed standards for several hours until combustion is stabilized. In this example, a start-up period of just a few hours would exceed the standard of 0.02 lb/MMBTU. Similar examples could be generated for the other pollutants regulated in the proposal, given more time to comment.
It is important to note that in the above scenario, the actual concentration emitted is held constant. In real situations this may not be the case. It is very common in industry for certain control devices to be out of operation during periods of start-up due to the nature of the equipment. Electrostatic precipitators (ESPs) must typically warm-up to be effective. This practice is necessary to ensure that boilers are started up in a safe manner. Premature starting of this equipment will lead to short term stability problems that could result in unsafe actions and longer term degradation of ESP performance due to fouling, increased chances of wire damage or increased corrosion within the chambers. Vendors providing this equipment make it part of the standard operating procedures. An example from a vendor manual is attached in Appendix I. During periods of start-up, combustion starts and as fuel is introduced the ESPs warm-up on a designated curve that could last for between 5 and 8 hours. As the control device is heated up additional fuel is added until the ESP meets its design temperature and normal fuel firing resumed. Like the example provided above, during such periods it is likely that emissions will exceed the standards proposed and would never be able to recover to meet the average limitations.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 257

Comment: AF&PA applauds the fact that EPA is allowing the use of emissions averaging and common stack monitoring in its proposal. However, in the context of periods of start-up and shutdown, AF&PA does not see how either of these provisions would be particularly useful. For example, if a site has two boilers, one of which routinely achieves levels below the standard and one of which slightly above the standard, but averaged are able to achieve the required standard. It is unclear to AF&PA how these standards could be met during periods when the boiler with the lower emission rate is not operating. The problem is compounded when applied to a common stack where it is possible that different units could start-up and shutdown at differing times within an averaging period. Under these situations, it very unlikely that the proposed numeric limitations would be met First, for the reasons related to more than one unit with differing emission rates and second due to the start-up characteristics and inability to meet certain limitations largely due to the impact of oxygen levels.

Response: See the preamble for common stack monitoring and changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 258

Comment: Given the limited carbon monoxide data and total absence of startup and shutdown emissions information for other pollutants from the test run data relied on by EPA to set the proposed standards and the infeasibility, if not impossibility, of collecting data from such brief operation periods for other pollutants, it is appropriate for EPA to set work practices for these events for boilers and process heaters. Section 112(h) allows EPA to set work practice standards for situations where “it is not feasible in the judgment of the Administrator to prescribe or enforce an emission standard . . . .” CAA § 112(h)(1); 42 U.S.C. § 7412(h)(1). Gathering data for other pollutants from startup and shutdown periods would be nearly impossible given the brief nature of these periods as well as the need to define the exact time period for what is considered “startup” and/or “shutdown” and the fact that CEM data would almost be required to collect such data that does not exist for a number of the pollutants proposed to be regulated. Moreover, the definition of “not feasible to prescribe or enforce an emission standard” is defined in the CAA as any situation where “the application of measurement methodology to a particular class of sources is not practicable due to technological and economic limitations.” CAA § 112(h)(2); 42 U.S.C. § 7412(h)(2). Startup, shutdown, and malfunction episodes fit squarely within this definition for the reasons outlined above and would justify the agency setting work practices to address emissions during these periods. Furthermore, a work practices approach for these periods would be in keeping with the statute’s requirement that MACT standards be “achievable” as well as with the requirement that a MACT standard apply at all times.

Response: See the preamble for response to how EPA adjusted CO emission limits and compliance mechanisms, and changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 259

Comment: A work practices approach for these periods also would be consistent with EPA's recently promulgated MACT standards for compression ignition reciprocating internal combustion engines (CI-RICE). See National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines, Final Rule, 75 Fed. Reg. 9648 (Mar. 3, 2010). Based on comments received from stakeholders, EPA finalized work practice standards for startup because the agency determined that it was "not feasible to finalize numerical emission standards that would apply during startup because the application of measurement methodology to this operation is not practicable due to technological and economic limitations." Id. at 9656. According to EPA, applicable test methods that would be needed to measure during these events "do not respond adequately to the relatively short term and highly variable exhaust gas characteristics occurring during these periods." Id. at 9665. Furthermore, EPA determined that the cost for testing all the engines affected by the rule to get the necessary data could be more than $1 billion. See id. Startup and shutdown periods for boilers encounter similar testing challenges and costs.
A work practices approach for startup and shutdown is also supported by the recent draft ICR for pulp and paper sources (EPA-HQ-OAR-2007-0544-0003 ,pulp and paper survey overview). In that action EPA is proposing to collect information on the following:
Questions pertaining to emission unit startup and shutdown are asked in order to provide EPA with an understanding of the duration, emissions potential, work practices, and control mechanisms of startup and shutdown events for the wide variety of equipment used at pulp and paper mills. The EPA is considering standards that could apply during startup and shutdown events (or whether the current standards developed for normal operation should apply) in light of the December 2008 vacatur of the NESHAP startup, shutdown, and malfunction exemption in 40 CFR Part 63 subpart A.
Here clearly EPA is interested in understanding more about actions and work practices that are employed currently in order to determine the appropriate course of action in establishing standards during such periods. It is not clear why EPA would not consider this same type of information in relation to boilers and process heaters.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)

Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 260

Comment: EPA argues in the preamble to the Proposed Boiler MACT states that malfunction periods should not be viewed as a "distinct operating mode," and thus, emissions from these periods do not need to be factored into developing the MACT floor levels. See id. Moreover, EPA states that even if malfunctions were to be considered a distinct operating mode, it would be "impracticable to take malfunctions into account in setting CAA section 112(d) standards for major source boilers and process heaters" given that these episodes are by definition sudden and unexpected events which vary in degree, frequency, and duration. Id.

Considering that EPA's proposed MACT standards are supposed to apply at all times, the implication is that periods of malfunction also are covered by the MACT standards that apply during normal operations. This directly conflicts with the statutory requirement that the MACT standard be "achievable." EPA has failed to recognize that it is likely that even best performers will experience malfunctions. It is possible for pollution control equipment to fail in various ways. Electrostatic fields trip, power failures do occur, fabric filters fail, scrubber pumps fail even at best performers and despite the best efforts of companies to prevent and minimize such events. Industry can and does work to minimize such periods, but they do occur. Further, manufacturers of such equipment routinely make emission guarantees for normal operations and although they sometimes oversize equipment to account for some of the variability described above, it is very doubtful that vendors would provide sufficient numerical guarantees for equipment under such situations.

Given that the floor data does not consider malfunctions and that the statute requires that the MACT standard be "achievable," EPA should set work practice requirements to address periods of malfunctions as well. As noted above, section 112(h) allows EPA to set work practice standards for situations where "it is not feasible in the judgment of the Administrator to prescribe or enforce an emission standard . . . ." Similar to startup and shutdown, malfunctions fit with the situations described in the definition of "not feasible to prescribe or enforce an emission standard" as any situation where "the application of measurement methodology to a particular class of sources is not practicable due to technological and economic limitations." Emission testing for malfunctions would be near impossible to conduct given the sporadic and unpredictable nature of the events. As noted earlier, EPA acknowledges in the preamble to the Proposed Boiler Rule that it is "impracticable" to take periods of malfunctions into account when setting emissions standards given the "myriad different types of malfunctions that can occur across all sources in the category" and that "malfunctions can vary in frequency, degree, and duration, further complicating" the standard setting process. Proposed Boiler MACT Rule at 32,013. Section 112(h) work practice standards, therefore, are well-suited to address malfunction periods and the complexities and challenges surrounding collecting data and establishing numerical standards for those events.

For these reasons, AF&PA believes that it is appropriate for EPA to revisit this issue. AF&PA suggests that EPA propose work practice standards that would allow sources a certain time period for start-up, shutdown and malfunction events and as long as certain procedures are followed, then compliance would be met. Those work practice standards should require the development and implementation of an emissions minimization plan that will result in (a) minimizing emissions during such events that would exceed otherwise applicable emission limitations, and (b) for malfunctions that will cause the unit to exceed otherwise applicable emission limitations, promptly identifying and implementing measures to remedy the malfunction. While there may be some instances where standard work practices can be identified for a type of source, AF&PA cautions that overly prescriptive and non-facility-specific requirements can actually be counterproductive, restricting the operators' flexibility in a way that hampers their ability to troubleshoot or respond to an event, or that compromises safety. The plan itself should not be incorporated into the Title V permit. The plan should be an evolving document, and it would be very cumbersome to have to seek a modification of the Title V permit every time the plan changed. If the details of the emissions minimization plan had to be made part of the permit, facilities would tend to make the plans less specific and therefore probably less useful. For the same reason, these plans should be maintained at the facility rather than being required to be submitted to the permitting authority with the Title V application or otherwise.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 261

Comment: EPA could establish a threshold of exceedances either a number or percentage of operating times that could occur during a quarterly or six month period before a violation occurs. This methodology is consistent with other MACT standards such as 40 CFR 63 Subpart S and MM; these exceedances could include startup, shutdown and malfunctions.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 300

Comment: Sources will not be able to meet some operating parameter limits on startup.
As stated in the comments related to appropriate averaging times and related to startup and shutdown, many types of control equipment are not in full operational mode while a boiler is starting up. Therefore, operating parameter limits will not always be feasible to meet during startup. EPA should instead establish work practices for the startup period, in lieu of requiring operating parameter limits to be met.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Stephen R. Gossett
Commenter Affiliation: Eastman Chemical Company
Document Control Number: EPA-HQ-OAR-2002-0058-3137.1
Comment Excerpt Number: 46

Comment: EPA should establish work practice standards instead of numerical emissions standards for boilers and process heaters operating during periods of startup and shutdown.

It is inappropriate to require compliance with numerical emissions standards that are achievable during periods of steady-state operation during periods of startup and shutdown. Institutional, commercial and industrial boilers, like their larger Electric Generating Unit (EGU) analogs, require an extended period of startup during which most, if not all, equipment in the boiler and pollution control systems are not operating in their normal condition. This extended startup period, typically several hours, is required due to equipment integrity concerns, limitations of the technologies, or safety concerns:

* Equipment Integrity – For example, a Fabric Filter (FF) cannot be put into service until the flue gas temperature is above the dewpoint. This requires that all heat transfer surfaces, ducts and flues from the combustion zone to the FF inlet be warmed up from ambient temperatures to dewpoint temperature (which varies by fuel type and fuel constituents, but is typically in excess of 140oF / 60oC). It takes a considerable amount of time, typically several hours for larger units, to warm up this considerable mass of steel: waterwall tubes, superheater tubes, reheater tubes, economizer tubes, casings, turning vanes, air preheaters, ducts and inlet plenums. During this warmup period, the FF cannot be put into service without risking catastrophic failure of the bags and intensive corrosion damage to the FF. This limits a unit's ability to control particulate matter and mercury during the several hours of startup.
* Limitations of the Technology – For example, units equipped with a Spray Dryer Absorber (SDA) for acid gas removal are limited in the amount of reagent slurry that can be injected into the flue gas during startup. The slurry federate is limited due to the nature of the technology by the amount of moisture the flue gas can evaporate. This in turn requires that a minimum temperature be achieved by the flue gas before the slurry federate can be initiated, and imposes a lengthy period of time during which the slurry federate is significantly limited until all the upstream heat transfer surface and ductwork has been warmed up. As such, SDA cannot remove Hydrogen Chloride in significant quantities for several hours after the unit is first fired.
* Safety Concerns – For example, reductions in the amount of time required to warm the boiler system up could be realized by increasing the ramp-rate of adding fuel to the unit. In theory, a boiler could be brought from first flame to full load in a matter of minutes, but decreasing the warm-up period from what the OEM recommends risks severe metallurgical stresses due to rapid changes in temperature and wide variances in temperatures across boiler and duct parts. Immediate failures could occur if inconsistent heating caused tears or ruptures in support steel or heat transfer surfaces, posing considerable risk to personnel in the plant. Failure rates would also increase due to the considerable stresses introduced by rapid heating and cooling cycles, yielding

failures at unpredictable times (steady state operation or future startups or shutdowns). For this reason, OEM recommendations for startup times are closely followed across industry.

EPA makes a mistaken assumption that startups and shutdowns are "predictable and routine". Industrial facilities, unlike electric utilities, typically operate a large number of smaller units of Eastman Boiler MACT Comments varying ages instead of operating a small number of very large units. When normal equipment failure rates (e.g., tube leaks) are multiplied across a large number of units, the total number of unit failures can be significantly larger at industrial facilities. Eastman operates a facility with over a dozen boilers, which average more than two unplanned outages per unit above and beyond each unit's planned outage in any given year. It is not uncommon for unplanned outages to occur in clusters, such as when a given component (e.g., an economizer) might suffer a failure due to corrosion or erosion. Repairs may fix the failure of any identified vulnerable areas nearby, but the root cause of the failure could be occurring in multiple areas that are not easily identified, resulting in additional failures in a short timeframe.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Stephen R. Gossett
Commenter Affiliation: Eastman Chemical Company
Document Control Number: EPA-HQ-OAR-2002-0058-3137.1
Comment Excerpt Number: 48

Comment: EPA should establish work practice standards issued under section 112(h) of the Clean Air Act to ensure emissions are minimized during startups and shutdowns without unreasonably requiring sources to attempt to comply with steady-state emission standards. EPA should add provisions to require sources to develop and adhere to operating practices specific to the unit's design, fuel type, and OEM recommendations that will ensure emissions minimization without forcing owner/operators to choose between putting their equipment and personnel at risk versus failing to comply with this rule. Such an operating practice should be crafted to be flexible, given the wide variety of boiler sizes, types, vintages, and fuels fired, and should be developed by the source based on OEM recommendations. General guidelines could include:

• Sequencing of equipment startups, per OEM recommendations
• Startup time durations, per OEM recommendations, and
Provisions to clearly define what constitutes "online" versus "startup". This could be crafted to mean a percentage of the unit's maximum continuous rating, or steam temperature/pressure, etc.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Stephen R. Gossett

Commenter Affiliation: Eastman Chemical Company
Document Control Number: EPA-HQ-OAR-2002-0058-3137.1
Comment Excerpt Number: 49

Comment: Eastman notes that EPA followed a work practice approach in its final rule for Reciprocating Internal Combustion Engines (RICE) issued on March 3, 2010. There, EPA concluded "it was not feasible to prescribe a numerical emission standard for stationary CI engines during periods of startup because the application of measurement methodology to these engines is not practicable due to the technological and economic limitations described below." (75 Federal Register 9665). Many of the reasons EPA articulates for this decision apply to the boiler and process heater source category regarding the accuracy of the stack gas sampling methods during transient load cases like startup. Eastman recognizes that EPA has set work practice standards in the RICE rule by limiting startups to 30 minutes. We agree this is appropriate. However, when it comes to boilers and process heaters, it is a much more complicated issue. Given the variety of units, operating pressures and temperatures, etc., we do not believe it is practical to set startup and shutdown periods on a "one-size fits all" basis. Rather, each source should work with their permitting authority to establish and obtain approval of appropriate work practice standards.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: W. Randall Rawson
Commenter Affiliation: American Boiler Manufacturers Association
Document Control Number: EPA-HQ-OAR-2002-0058-2698.1
Comment Excerpt Number: 3

Comment: In establishing achievable MACT emission standards, EPA should address the anticipated startup, shutdown and malfunction conditions that may be experienced across the wide range of boiler designs and applications. To the extent that emission standards must apply during periods of startup, shutdown and malfunction, they must be set in a manner which adequately accounts for anticipated emissions during those conditions. ABMA is concerned that the data on which EPA has relied does not adequately represent considerations that may affect such emissions, such as boiler size, usage of flue gas recirculation ("FGR"), steam pressure and temperature. These issues are particularly relevant to startup conditions, which are reasonably anticipated and can be evaluated in the standard-setting process. For example, the following factors should be considered in relation to CO emissions during startup:

* During cold start, furnace temperature is low and higher CO emissions will result;
* High pressure boilers take longer to come up to temperature;
* Super heated steam applications take longer to reach their normal operating conditions;
* Low NOx, high FGR applications have very low air velocities at the burner during cold start, because FGR cannot be introduced to the burner before it reaches a certain temperature, thereby reducing volumetric flow and resulting in higher CO emissions;

* A typical cold start CO emission level that may range up to 400 ppm or higher on oil, and the following wide range of boiler warm-up periods based on boiler type may result in significantly higher average CO emissions than experienced at steady-state operation: [Footnote: For example, assume a typical industrial water tube low NOx gas burner application mounted on a super heated steam boiler may achieve 15 ppm CO at steady state operation. Conservatively assuming a four hour warmup period during which 200 ppm is experienced for the first two hours of startup and 100 ppm for the second two hours, the 24 hour average emission would be 200 ppm x 2hr/24hr + 100ppm x 2hr/24hr + 15 ppm x 18hr/24hr = 36.25 ppm.]

Firetube boilers: 1-4 hours
Industrial watertube boilers (150 psig): 3-6 hours
Super heated industrial watertube package boiler: 4-8 hours
Super heated field erected boilers – 8 hours or more

Response: See the preamble for response to how EPA adjusted CO emission limits and compliance mechanisms, and changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: W. Randall Rawson
Commenter Affiliation: American Boiler Manufacturers Association
Document Control Number: EPA-HQ-OAR-2002-0058-2698.1
Comment Excerpt Number: 4

Comment: EPA's preamble to the Proposed Boiler MACT does acknowledge an attempt to incorporate startup and shutdown emissions through its consideration of daily or monthly average CEMS data from the best performing units. However, EPA has not demonstrated that its data set adequately addresses the variability in startup length and associated emissions experienced in boilers of various design and load requirements. Therefore, ABMA believes that EPA should: (1) allow a period of time for startup, based on boiler type, during which emissions limits would not apply; (2) establish an alternative emission limit for startup periods based on boiler types within a subcategory and their load; or (3) review the data set and the anticipated startup conditions of various boiler types to ensure that the emission limits set for each subcategory are representative of multiple boiler designs and emission variability within the subcategory. The alternatives for defining reasonable emission standards for startup conditions should extend to startups occasioned by the range of circumstances, such as cold start after a period of scheduled non-operation, as well as startup occurring after a malfunction during which cold-start parameters often apply. Additionally, EPA should extend similar consideration to emissions variability during shutdown periods. During these periods, considerable volumetric post- and pre-purge air change requirements serve to cool boilers down in an attempt to relieve the combustion chamber of unburned fuel and of flue gases prior to re-ignition sequence.

Response: See the preamble for response to how EPA adjusted CO emission limits and compliance mechanisms, and changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: W. Randall Rawson
Commenter Affiliation: American Boiler Manufacturers Association
Document Control Number: EPA-HQ-OAR-2002-0058-2698.1
Comment Excerpt Number: 5

Comment: ABMA also supports a limited allowance for malfunction periods. The term "malfunction" should be more precisely defined to include the variabilities of malfunction. Malfunction can range from the need for immediate and complete shutdown to malfunctions like an interruption in fuel supply or an inoperative CEMs that will require only a short downtime. A plant should not be required to completely shutdown due to a malfunction of the boiler, burner or boiler-related equipment. Once defined, a malfunction should be regulated by alternative limits applied during the time it takes to complete corrective action and get the boiler back to normal operational mode.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Chris Greissing
Commenter Affiliation: Industrial Minerals Association
Document Control Number: EPA-HQ-OAR-2002-0058-2740.2
Comment Excerpt Number: 6

Comment: EPA Has Not Adequately Provided for SSM Events. EPA states it has taken into account startup and shutdown periods in setting MACT limits because data used in setting the standards includes periods of startup and shutdown and because the averaging times are daily or monthly periods. 75 Fed. Reg. at 32013. Therefore, EPA concludes no special limits are needed for startup and shutdown which it says are predictable and routine. However, EPA has not shown that the data on which it relies actually includes meaningful data from startup and shutdown events. Certainly stack test data, by definition, is obtained during representative conditions and does not include startup and shutdown events. To the extent EPA relied on CEMS data for PM or CO, it is not evident that such data included meaningful data for startup or shutdown events. Further, EPA's assumption that boilers do not normally startup or shutdown more than once per day is not accurate for many boilers which may start up multiple times in a day. As noted above, the practice for at least some soda ash facilities is that during startup the ESP does not come on line until the exhaust temperature reaches 350F, which means that PM emissions during that time are not the same as during normal operations. The result is that the proposed MACT limits do not represent what is "achievable" during startup and shutdown, contrary to Section 112(d) of the Clean Air Act and Sierra Club v. EPA, 167 F.3d 658, 665, supra.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Chris Greissing
Commenter Affiliation: Industrial Minerals Association
Document Control Number: EPA-HQ-OAR-2002-0058-2740.2
Comment Excerpt Number: 7

Comment: EPA correctly recognizes that malfunction events are not predictable or routine aspects of a facility's operation and that malfunction emissions, therefore, do not have to be factored in to the MACT limits. EPA's proposal for dealing with malfunctions that result in a failure to comply with MACT limits is to "determine an appropriate response based on, among other things, the good faith efforts of the source to minimize emissions during malfunction periods , including preventative and corrective actions, as well as root cause analyses . . ." No provision for malfunctions is actually included in the proposed rule itself. To the contrary, Table 6 of the rule states that standards must be met at all times, including malfunctions. It is unreasonable to expect sources to rely on preamble language that is contradicted by the rule itself, and that provides for an entirely subjective after-the-fact judgment, as a satisfactory malfunction provision. If, as the EPA admits, the limits were set without taking malfunction events into account, and if malfunctions are neither avoidable nor predictable, the only satisfactory approach is to excuse noncompliance that results from malfunctions if reasonably defined requirements are met. One way to accomplish this would be to require sources to develop malfunction plans and excuse emission exceedances due to malfunction if the plans are followed.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Melvin E. Keener
Commenter Affiliation: Coalition for Responsible Waste Incineration (CRWI)
Document Control Number: EPA-HQ-OAR-2002-0058-2824.1
Comment Excerpt Number: 8

Comment: EPA's proposed requirement that facilities meet steady-state standards during SSM events is not logical nor is it lawful.

EPA's proposal to require industrial boilers and process heaters to'comply with the same emission standards during periods of startup, shutdown, malfunction, and steady state conditions is neither logical nor lawful.

Before the court's decision in Sierra Club v. EPA, 551 F.3d 1019 (DC. Cir 2008) ("SSM Decision") the DC Circuit had consistently held that technology-based standards must contain exemptions or less stringent standards during periods of startup; shutdown, and malfunction (SSM) than would usually apply during steady state periods.

For example, in Portland Cement Ass’n v. Ruckelshaus, 86 F.2d 375, 396, 398 (D.C. Cir. 1973), cert. denied, 417 U.S. 921 (1974) ("Portland Cement"), the DC Circuit recognized that "‘start-up’ and ‘upset’ conditions, due to plant or emission device malfunction, is an inescapable aspect of industrial life and that allowance must be made for such factors in the standards that are promulgated. The Court, which was addressing EPA’s NSPS rules, also noted that including the startup, shutdown, and malfunction provisions "imparts a construction of ‘reasonableness’ to the standards as a whole and adopts a more flexible system of regulation than can be had by a system devoid of ‘give." Id. at 399.

In Essex Chem. Corp. v. Ruckelshaus, 486 F.2d 427, 432 (D.C. Cir. 1973); petitioners argued that lesser or no standards should apply during startup, shutdown or malfunction conditions. The Court agreed, holding that such provisions "appear necessary to preserve the reasonableness of the standards as a whole." Id. at 433. And in NRDC v. EPA, 859 F.2d 156 (D.C. Cir. 1988), the court held that, although water-quality permit limits need not incorporate an "upset defense," "[a] technology-based standard discards its fundamental premise wheh it ignores the limits inherent in the technology." Id. at 208 (citing Marathon Oil. Co. v. EPA, 564 F.2d 1253, 1273 (9th Cir. 1977)). Consequently, because all pollution control technologies will occasionally malfunction and take time to get to their steady-state conditions (such as during startup, shutdown or malfunction), "achievable" technology-based standards must contain provisions for compliance during such unavoidable events.

Now that the court has decided that MACT compliant standards must apply during periods of SSM, the Agency must develop standards that are "achievable" with this ruling in mind. The court has stated that for standards to be "achievable," they must be achievable under the most adverse circumstances which can reasonably be expected to recur, Sierra Club, supra, 665 citing National Lime Ass’n v. EPA 627 F2.d 416 (D.C. Cir. 1980) ("National Lime 1’). Consequently, since startup, shutdown, and malfunctions will recur, EPA must set standards that must be achievable during those times.

The standards EPA are proposing for industrial boilers and process heaters are not capable of being complied with during periods of SSM. For example, facilities with baghouses cannot comply during startup periods because they have to bypass the bags until the temperature gets above the condensation point. Otherwise, they will prematurely damage their bags. There are similar issues for other types of air pollution control devices. Despite this, EPA states in the preamble that they have taken into account startup and shutdown periods in establishing these standards (75 FR 32012) and is not establishing different standards for these periods (75 FR 32013). EPA’s reasons are that boilers do not normally startup or shutdown more than once a day and that daily or monthly averages are used to show compliance with the standards. EPA is correct that boilers typically do not startup more than once a day perhaps because it may take 36 to 48 hours to startup a large boiler (required time to heat up the refractory to avoid equipment damage). The major flaw in EPA’s reasoning, however, is that EPA did not include emissions data during either startup or shutdown in the development of these standards; all data collected was under steady-state conditions. Since emissions under non-steady-state conditions may vary significantly, they could significantly alter the Agency's calculations. Thus, the standards are not properly set.

In addition, EPA does not consider a malfunction as a distinct operating mode. CRWI disagrees. Malfunctions occur. Just because EPA states that the goal of best performing sources is to have no malfunctions (75 FR 32013) does not make malfunctions go away. Even the best operated and maintained facilities will have malfunctions. For example, any facility that is tied into the external electric power grid (most have at least a small tie-in) will face power disruptions potentially causing malfunctions. We have all lost power in our homes at one point in time — it's an inevitable.

We agree, however, that it is difficult to develop the data necessary to set numerical emissions limits for transient conditions. For example, if a facility ran a Method 5 test during startup, a single test would take 6 — 8 hours (each run takes at least an hour, three runs are required for a valid test, and the operator must have time in between runs to change out sampling equipment). During those eight hours, the conditions would have changed so significantly that it would be virtually impossible to understand what that data meant or to extrapolate that data to other transient conditions. The same is true for CEMs readings.

As such, EPA must establish, and explain why facilities can comply with the standards it promulgates. As the court noted in National Lime I, "by failing to explain how the standard proposed is achievable under the range of relevant conditions which may affect the emissions to be regulated, the Agency has not satisfied this initial burden." National Lime I, supra, at 433.

So, while it is appropriate to use data gathered under steady-state conditions to set emission standards for steady-state conditions, it is not appropriate (from either a logical or legal perspective) to apply those standard's to non steady-state conditions. Thus, EPA must find an alternative method for facilities to show compliance during these phases of operation. Congress provided for this when they set up the work practice provisions of 112(h). Here Congress stated that EPA may set work practice standards if it is not feasible to prescribe or enforce an emissions standard. CRWI believes that it is infeasible to gather data during startup, shutdowns, or malfunctions simply because there are no EPA approved methods to, make measurement during non-steady-state conditions and malfunctions, by definition, are sudden and infrequent. In the final Hospital/Medical/Infectious Waste Incinerator rule, EPA agrees with this. At 74 FR 51394, EPA states "It would be very difficult to do any meaningful testing during such an event because the exhaust flow rates, temperatures, and other stack conditions would be highly variable and could foul up the isokinetic emissions test methods (thus invalidating the testing)." The obvious choice for these conditions are work practice standards.

In summary, standards developed under steady-state conditions cannot incorporate the variability that occurs during SSM events. Expecting a facility to comply with emission standards developed under steady state conditions during SSM events is neither logical nor lawful. Thus, EPA should modify the proposed regulatory language to require facilities to meet emission standards (derived from data gathered understeady-state conditions) during normal operations. In addition, CRWI suggests EPA set work practice standards for startup, shutdown, and malfunctions. This would satisfy both Congress' intent that 112 standards apply at all times and the recent court ruling. Alternatively, EPA could gather data during startups, shutdowns, and malfunctions and incorporate this data into the data gathered during steady-state conditions to set numerical emission standards. Emissions standards based on data collected during all modes of operation could then reasonably apply at all times.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Melvin E. Keener
Commenter Affiliation: Coalition for Responsible Waste Incineration (CRWI)
Document Control Number: EPA-HQ-OAR-2002-0058-2824.1
Comment Excerpt Number: 9

Comment: EPA needs to allow an alternate oxygen correction factor during these events. During the first part of startup and the last part of shutdown, the oxygen concentrations will approach ambient concentrations. When this occurs, the equation used to calculate the correction factor will approach infinity (dividing by - zero). Under these conditions, it is not appropriate to apply the oxygen correction factor as proposed. The HWC MACT rule allows facilities to set up an alternate correction factor for these conditions. One example of how this problem can be addressed can be found at 40. CFR 63.1206(c)(2)(iii).

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Melvin E. Keener
Commenter Affiliation: Coalition for Responsible Waste Incineration (CRWI)
Document Control Number: EPA-HQ-OAR-2002-0058-2824.1
Comment Excerpt Number: 10

Comment: If EPA keeps the provisions that the facility must comply with the standards are all times, CRWI sees no reason facilities have to record and report "SSM" events. The proposed language contains some inconsistencies. For ‘ example, Table 10 proposes that the requirement to develop an SSM plan does not apply. fn addition, EPA also proposes an immediate report if the facility does not follow their SSM plan. Since Table 10 proposes that the requirement to develop SSM plans (§ 63.6(e)(3)) does not apply, a facility cannot fail to follow a plan it is not required to have. CRWI suggests that EPA re-examine the proposed rule for any provisions that are inappropriate, unnecessary, or redundant should EPA remove the SSM provisions in the final rule.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Mike D. Craig
Commenter Affiliation: New Energy Corp.
Document Control Number: EPA-HQ-OAR-2002-0058-2695.1
Comment Excerpt Number: 11

Comment: Table 9 (2) states that "you must submit...an immediate startup, shutdown, and malfunction report if you had a startup, shutdown, or malfunction during the reporting period that is not consistent with your startup, shutdown, and malfunction plan." NEC would like clarification as to where the requirement to have a startup, shutdown, and malfunction plan exists, other than in the general requirements section of 40 C.F.R. § 63.6(e)(3) which, according to Table 10, does not apply to subpart DDDDD.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Robert D. Morrison
Commenter Affiliation: Abbott Laboratories
Document Control Number: EPA-HQ-OAR-2002-0058-2764.1
Comment Excerpt Number: 15

Comment: The proposed Boiler MACT standard includes limits that apply at all times when it is likely that startup, shutdown, and malfunction emissions will be higher. Work practice standards for boiler startup, shutdown, and malfunction would be more effective and realistic (40 CFR 63.7500(a), 75 FR 32012). The proposed rule sets emission limits that apply at all times (40 CFT 63.7500(a), 75 FR 32012). This approach compounds the concern that CO emission limits have been set too low for realistic operations, based on inadequate data that reflect a limited group of very new units that is not representative of normal boiler performance. As a result, the proposed rule potentially creates a large number of units that are trapped with unachievable emission limits. A better solution would be for individual boilers to establish work practice standards for periods of startup, shutdown, and malfunction. The use of such standards, when focused on industry- and facility- specific work practices, provides for emission limits and effective control consistent with boiler design factors.

Response: See the preamble for response to how EPA adjusted CO emission limits and compliance mechanisms, and changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Leonard W. Sandridge
Commenter Affiliation: University of Virginia
Document Control Number: EPA-HQ-OAR-2002-0058-2769.1

Comment Excerpt Number: 17

Comment: We are concerned that 12-hour rolling average operating limits are insufficient to dampen the impacts of SSM events, especially benign events such as startup.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Donald R. Schregardus
Commenter Affiliation: Department of Defense
Document Control Number: EPA-HQ-OAR-2002-0058-2763.1
Comment Excerpt Number: 18

Comment: With due consideration to safety and operational requirements, some of the pollution control equipment (such as baghouses) of already permitted sources are designed to have different procedures of operation during SSM events. As a consequence, these sources will not be able to comply with the proposed standards during SSM events.

Per Section 63.7505(a), the standards set forth in the rule apply at all times. There is no specific allowance for SSM periods relative to the emission limits in the rule. EPA discusses in section III.E. on page 32012, that startup and shutdown periods were taken into account when setting the standards which are daily or monthly averages and thus achievable even when a startup or shutdown occurs. However, in Tables 1 and 2 of the proposed rule, carbon monoxide is the only pollutant for which an averaging period is specified. The emission limits for particulate matter does not appear to be based on an average over a time period. This is an unachievable standard since some pollution control devices cannot be in service until temperatures rise and conditions stabilize, during which emissions are known to exceed such low emission limits.

For example, a DoD facility operates baghouse control devices that must be bypassed during startup and shutdown due to explosion risk. This requirement is a documented standard operating procedure implemented at the facility and is based on recommendations of the equipment manufacturer. Because of these requirements for safety considerations, the Agency should adopt procedures similar to what was done in the Miscellaneous Organic Chemical Manufacturing NESHAP (40 CFR Part 63, Subpart FFFF [40 C.F.R. § 63.2450(q)]. This provision allows facilities that cannot meet an emission limit for safety reasons, to submit documentation in their precompliance report explaining why an undue safety hazard would be created if the air emission controls were installed, and to describe the procedures that you will implement to minimize HAP emissions from these vent streams. This provision is provided where it is unsafe to control the source at any time but it could be used as a model in the boiler rule to allow sources to avoid control during startup and shutdown when safety issues prevent use of controls.

The final rule should contain a provision similar to 40 CFR Part 63, Subpart FFFF, 63.2450(q) to exclude SSM events from the emission limits when it can be demonstrated that it is necessary to bypass emission controls for safety reasons.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: William A. Moore
Commenter Affiliation: Luminant
Document Control Number: EPA-HQ-OAR-2002-0058-2780.1
Comment Excerpt Number: 19

Comment: EPA should provide an affirmative defense for start-up, shutdown, and malfunction. Luminant opposes EPA's proposal to omit from the rule an affirmative defense for excess emissions of HAP during periods of start-up, shutdown, and malfunction ("SSM"). EPA's proposed rule unnecessarily disregards the special circumstance of excess emissions of HAP during SSM, and its omission would be an over-reaction to the D.C. Circuit's decision.

Citing the D.C. Circuit's opinion vacating the SSM exemptions in the "General Provisions Rule" of 40 C.F.R. §§ 63.6(f)(1) and (h)(1) (which exempted sources during periods of SSM from compliance with the emission standards), EPA has "established standards in [the proposed] rule that apply at all times." 75 Fed. Reg. 32,006, 32,012 (June 4, 2010), (citing Sierra Club v. EPA, 551 F.3d 1019 (D.C. Cir. 2008). In the case cited by EPA, the D. C. Circuit was reviewing a challenge to an SSM exemption and read §§ 112 and 302(k) of the CAA together to conclude that "Congress has required that there must be continuous section 112- compliant standards," and that "the SSM exemption [in the General Provisions] violated the CAA's requirement that some section 112 standard apply continuously." 551 F.3d at 1027-28 (emphasis added). However, EPA has gone well beyond the D.C. Circuit's holding, by not only providing no SSM exclusions, but also by offering no alternative provisions addressing excess emissions during periods of SSM.
EPA concludes in the proposed rule that because startup and shutdown are part of a source's "routine operations," these periods are "already addressed by the standards."

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: William A. Moore
Commenter Affiliation: Luminant
Document Control Number: EPA-HQ-OAR-2002-0058-2780.1
Comment Excerpt Number: 20

Comment: With respect to malfunctions, the proposed rule states that if a source fails to meet the applicable standards as a result of a malfunction, "EPA would determine an appropriate response based on, among other things, the good faith efforts of the source to minimize emissions during malfunction periods, including preventative and corrective actions, as well as root cause analyses to ascertain and rectify excess emissions." Id. EPA should actually incorporate that intent into the rule, by expressly including an affirmative defense available to sources during periods of SSM.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: William A. Moore
Commenter Affiliation: Luminant
Document Control Number: EPA-HQ-OAR-2002-0058-2780.1
Comment Excerpt Number: 21

Comment: Consistent with EPA's guidance on SSM, EPA's proposed rule should include an affirmative defense during periods of SSM. Specifically, EPA should provide that, while periods of excess emissions during startup and shutdown might be considered violations, an owner could raise an affirmative defense. EPA has recognized that "for some source categories, even the best available emissions control systems might not be consistently effective during startup or shutdown periods."[Memorandum from Steven A. Herman, Assistant Administrator for Enforcement and Compliance Assurance and Robert Perciasepe, Assistant Administrator for Air and Radiation, to Regional Administrators, Regions I – X, State Implementation Plans: Policy Regarding Excess Emissions During Malfunctions, Startup, and Shutdown (Sept. 20, 1999) ("1999 Policy").] The operational realities of excess emissions during periods of SSM have been acknowledged by EPA in several instances. For example, in EPA's new source performance standards, EPA provides that opacity standards apply "at all times except during periods of startup, shutdown, malfunction, and as otherwise provided in the applicable standard." 40 C.F.R. § 60.11(c); see also 75 Fed. Reg. 10,174 (Mar. 5, 2010) (approving a source-specific federal implementation plan for the Navajo Generating Station that provides an affirmative defense against penalties resulting from non-compliance during periods of startup, shutdown, and malfunction.).

Including an affirmative defense is also consistent with EPA's policy regarding exclusions during periods of SSM. Unlike an exclusion, an affirmative defense does not excuse a source from continuous compliance. The affirmative defense – when established by the source – merely relieves the source of any penalty imposed as a result of non-compliance during a period of SSM. It does not relieve the source of the requirement to comply with the applicable standard.

Finally, EPA has recently approved similar affirmative defense provisions in several states' State Implementation Plans ("SIP"). For instance, in Colorado, EPA approved a SIP provision providing an affirmative defense during periods of startup and shutdown. See, e.g., 71 Fed. Reg. 8958 (Feb. 22, 2006). Similarly, EPA approved an affirmative defense in New Mexico's SIP for excess emissions during startup, shutdown, and malfunction related activities. See 74 Fed. Reg. 46,910 (Sept. 14, 2009). When EPA approved the Colorado and New Mexico revisions, it stated that the affirmative defense provisions were consistent with its 1999 policy provisions. See 71 Fed. Reg. at 8959; see also 74 Fed. Reg. at 46,912 (The "SIP submittal contains criteria to be considered when asserting an affirmative defense for an excess emission during startup or shutdown . . . that are similar, if not identical, to those in the 1999 Policy.”).

Nothing in the D.C. Circuit’s opinion precludes EPA from including an affirmative defense for excess emissions during periods of SSM. In fact, doing so would be consistent with 1) EPA’s recognition of various operational reasons a source might be in non-compliance; 2) EPA’s policy against exclusions (or similar provisions abrogating the CAA’s requirement to be in continuous compliance); and 3) EPA’s approval of similar SIP provisions. Accordingly, Luminant urges EPA to include an affirmative defense in the final rule.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-2702.1
Comment Excerpt Number: 38

Comment: CIBO notes that not all these data sets include periods of startup. In the stoker coal subcategory, the unit at DuPont in West Virginia did not note any periods of SSM in the CO Monitoring Template. Further, EPA’s graph of the CO CEMS data plotted vs boiler load for the Phillip Morris boiler in Virginia (the only pulverized coal boiler with CEMS data in EPA’s dataset) (see Appendix B-1 of the MACT floor memorandum) is wrong (it appears to plot the Excel row number vs. CO) and does not include data from boiler load below 100 MMBtu/hr. This boiler went through three startups during the 30 day period and the graph clearly shows elevated CO during low load periods and shows an inverse relationship of CO and boiler load. The average CO concentrations during periods of only "normal" operations was 35 ppm whereas the average CO concentrations during all periods (normal, shutdown, startup) was 27 ppm.

Response: See the preamble for response to how EPA adjusted CO emission limits and compliance mechanisms, and changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: David A. Buff
Commenter Affiliation: Golder Associates Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2801.1
Comment Excerpt Number: 39

Comment: EPA uses short term performance test results to set the standards rather than the results of long-term CEMS monitoring. As a result, the emissions data on which the standards are based do not, in fact, reflect or adequately accommodate emissions from periods of startup, shutdown, or malfunction.

To assure that startup, shutdown, and malfunction are appropriately accommodated, EPA must either ensure that the data on which the standard is based include representative data from such periods or, alternatively, set a separate work practice standard to properly accommodate startup, shutdown, and malfunction. Lastly, instead of using the UPL, EPA should use the upper tolerance limit ("UTL"), which is meant for use in situations where the available data does not represent the entire population.

Response: See the preamble for response to how EPA adjusted CO emission limits and compliance mechanisms, and changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: David A. Buff
Commenter Affiliation: Golder Associates Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2801.1
Comment Excerpt Number: 40

Comment: Additional concerns with SSM events and the proposed rules are as follows:

* Daily average for opacity is not adequate to cover SSM in situations where control device cannot operate until a certain flue gas temperature is reached.
* Sometimes cannot start control device before certain exhaust gas conditions are met during startup.
* EPA cannot assume that units only startup or shutdown once per day. Bagasse boilers sometimes startup/shutdown several times a day.

It is unlikely that boilers will be able to comply with the promulgated standards at all times, including startup and malfunction. This is especially true for CO, since CO emissions are a function of combustion efficiency, which is lower during startup and malfunction events.

Response: See the preamble for response to how EPA adjusted CO emission limits and compliance mechanisms, and changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: David A. Buff
Commenter Affiliation: Golder Associates Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2801.1
Comment Excerpt Number: 41

Comment: Enforcement of malfunction events should not be carried out on a case-by case basis. This would cause undue burden on the regulatory agencies. Consistent with other Clean Air Act (CAA) regulations [i.e., New Source Performance Standards (NSPS)], malfunction events should be excluded from meeting the emission limits. Absent any exclusion, a higher emission limit based on actual operation should be set, which applies only during malfunction events and is reflective of malfunction events.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: David A. Buff
Commenter Affiliation: Golder Associates Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2801.1
Comment Excerpt Number: 42

Comment: In the recent Reciprocating Internal Combustion Engine (RICE) MACT promulgation [Title 40, Part 63 of the Code of Federal Regulations (40 CFR 63), Subpart ZZZZ], EPA set startup and malfunction standards based on "minimizing startup time." EPA should promulgate a similar provision for boilers and process heaters.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: David A. Buff
Commenter Affiliation: Golder Associates Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2801.1
Comment Excerpt Number: 52

Comment: Some operating parameter limits may not be able to be met during startup conditions- there should be an exclusion for startup/shutdown.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 69

Comment: To address the decision in Sierra Club v. EPA, 551 F.3d 1019 (D.C. Cir. 2008), cert. denied, 2010 U.S. LEXIS 2265(2010), which vacated the exemption in 40 C.F.R. 63.6(f)(1) and (h)(1) for SSM periods, EPA proposes emissions standards in the MACT for industrial boilers and process heaters that apply at all times, including periods of malfunction, as well as startup and shutdown. For standards where EPA sets numeric limits, EPA must either; 1) treat malfunction as part of normal operating mode and then include the emissions during malfunction as part of the variation of the units emissions, or 2) treat malfunction as a distinct operating mode and establish work practices for malfunction periods.

In the preamble, EPA states malfunctions should not be viewed as a “distinct operating mode,” and thus, “emissions from these periods do not need to be factored into developing the MACT floor levels.” 75 Fed.Reg. 32013. EPA goes on to say:

For example, we note that Section 112 uses the concept of ??best performing“ sources in defining MACT, the level of stringency that major source standards must meet. Applying the concept of ??best performing“ to a source that is malfunctioning presents significant difficulties. The goal of best performing sources is to operate in such a way as to avoid malfunctions of their units. Id.

EPA‘s explanation is internally inconsistent. The statement that the goal of best performing sources is to avoid malfunction recognizes that best performing sources do occasionally malfunction. If malfunction is part of the regular operating mode of boilers and process heaters, then it should be part of the variation of the best performing units and included as part of the development of the floor.

EPA goes on to state that even if malfunctions were to be considered a distinct operating mode, it would be impracticable to take malfunctions into account in setting CAA section 112(d) standards for major source boilers and process heaters given that these episodes are by definition sudden and unexpected events which vary in degree, frequency, and duration. Id.
This however does not relieve EPA of its obligation to set standards that are achievable under Section 112(d)(2). A numeric standard that governs malfunction periods, but does not take malfunction emissions into account, is not achievable.

Consequently, EPA should set work practice requirements to address periods of malfunction. As noted above, section 112(h) allows EPA to set work practice standards for situations where “it is not feasible in the judgment of the Administrator to prescribe or enforce an emission standard…” Malfunctions fit within the situations described in the definition of “not feasible to prescribe or enforce an emission standard” as any situation where “the application of measurement methodology to a particular class of sources is not practicable due to technological and economic limitations.” Emission testing for malfunctions would be near impossible to conduct given the sporadic and unpredictable nature of the events. As noted earlier, EPA acknowledges in the preamble to the Proposed Boiler Rule that it is “impracticable” to take periods of malfunctions into account when setting emissions standards given the “myriad different types of malfunctions that can occur across all sources in the category” and that “malfunctions can vary in frequency, degree, and duration, further complicating” the standard setting process. Id. Section 112(h) work practice standards, therefore, are well-suited to address malfunction periods and the complexities and challenges surrounding collecting data and establishing numerical standards for those events.

Recommendation: EPA should adopt work practices for malfunction periods for any numeric standard.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 88

Comment: According to 63.7505, the requirements of the proposed rule apply at all times. However, it is clear that no turndown, startup and shutdown emissions data were included in the database used to generate the proposed emission limits and that boilers and process heaters cannot meet all of the proposed emission limitations during all periods of turndown startup and shutdown. In fact, it is forbidden by 63.7(e) of the Part 63 General Provisions for performance tests to include startup, shutdown or malfunction periods in performance tests, so it is impossible to demonstrate compliance during such periods, even if a unit might be able to meet the proposed emission limits. Even units that can be retrofitted with controls that allow achieving the emission limits during normal operations will be unable to meet the limits during turndown operations and some startups and shutdowns because many of the controls are not effective at the low stack temperatures that occur during high turndown, startup and shutdown periods.

On page 32013 of the preamble, EPA explains the reasons it feels startup and shutdown activities are “normal” operations and thus are not handling startup and shutdown periods differently.

For gas-fired units, EPA collected two 30 day sets of CEMS CO data. It is ridiculous to claim this insignificant amount of data establishes that startups and shutdowns are normal operations. It is clearly impossible for those two sets of CO data to represent the myriad of types of sources and operating conditions subject to this regulation. Furthermore, even those two data sets do not show compliance with the CO limit at all times and, based on the firing information, they do not

include any significant startup and shutdown operations and only one of the two includes any turndown operations [Footnote: With respect to the gas-fired boilers for which EPA collected CO CEMS data, no data were collected while these units were operating at low loads. The data for the CATesoro boiler was from 71 to 81 MM Btu/hr. Assuming the upper value representing near design load, this variation is only 88 to 100%, not representative of the full operating range for most gas boilers. The other gas fired boiler, WABOEINGRENTON, shows significant variation from 15 to 40 MMBtu/hr with CO peak at about 25 MMBtu/hr. It is also worth noting that the reported CO concentration from the WABOEINGRENTON testing is well above the level of 1 ppmv CO that EPA has proposed for Gas 2.] We discuss our review of those two data sets in Attachment D, but it is clear that they are not representative of the source category, of turndown operations, or of startup and shutdown emissions from even the two units monitored, much less startup and shut down of the myriad types of units in the source category.

Emissions resulting from pollutants contained in fuel (i.e., mercury and chlorine) are unlikely to be different during turndown, startup and shutdown periods, but a simple understanding of combustion suggests that particulate emissions are likely to be higher during poor combustion periods such as may occur during these times. The impact of startup and shutdown conditions on dioxin/furan emissions is unknown, but that provides little certainty for sources that will have to certify that they complied with the dioxin/furan limits during these periods. Since there is no significant averaging period provided for PM or dioxins/furans and no compliance monitoring is possible, there is no basis for a source to certify compliance during such periods. Even if there were a is significant averaging time, sources have no basis for certifying compliance since operating conditions, stack temperatures, firebox temperatures, air-to-fuel ratios and other significant parameters are significantly different during these periods than during normal operation. If ever there is a case to be made that the application of a system for measuring the effect of the control measure for enforcement purposes is not practicable (one of the CAA section 112(h) criteria) it is for PM and dioxin/furans during turndown, startup and shutdown operation. The case for not applying numerical emission limits to CO, the surrogate proposed for organic HAPs, during turndown, startup or shutdown is made later in section VI.C.

The Agency argues on page 32013 of the preamble that special consideration of startup and shutdown periods is not needed because startups and shutdowns are predictable and do not happen more than once per day. We are not sure why these factors matter. If emissions during startups and shutdowns are different than during normal operation, which they are, it doesn't matter that the startup or shutdown was predictable. The compliance average will still be impacted to the same extent. In general, startups often take more than a day to complete and most take a significant part of a day. The number of startups in a day does not matter, however. What matters is the level of emissions during the startup or shutdown and the duration of those emissions relative to the averaging time of the standard. Units with CO CEMS (units over 100 MMBTU/hr) have a 30 day averaging time under the proposal. It only takes 1 day at 30 ppm CO to exceed that standard and such days will be the rule rather than the exception during boiler and process heater startups. For units under 100 MMBTU/hr the CO averaging time is 12 hours (3 four hour performance test runs), though as mentioned previously such a test is not allowed to include startup and shutdown periods and for many reasons could not be used even if it were allowed. Thus, for CO for units under 100 MMBTU/hr, there is no compliance methodology specified or available for startup or shutdown periods and work practice requirements and the 112(h) criterion is certainly met for these units. For units over 100 MMBTU/hr, CO CEMS are specified, though measurement during startup and shutdown periods might be possible.

However, in order to have accurate measurements to show compliance with the specified CO limit for normal operation, the CO CEMS will have to be spanned to about 10 ppm and the high CO emissions that occur during turndown, startup and shutdown periods will be above the span of the instrument. All-in-all, it is clear that measuring CO for the purpose of demonstrating compliance during periods of significant turndown, startup or shutdown is not practical

Many startups and particularly initial startups, startups after any refractory work, and shutdowns involving special operations such as decoking or soot blowing are unlikely to be able to meet the CO limits, even with add-on controls. Good operating practices and manufacturers recommendations require equipment to be gradually warmed-up to operating temperature in order to prevent thermal damage to mechanical components. Equipment manufacturers often specify heat-up rates and require conformance with these rates for equipment warranty. In order to provide for proper dry-out of refractory and to avoid damage to the refractory, initial and-post refractory work startups must be done even more slowly than normal startups. These types of operations often take more than a day, as the firebox temperature must be raised at a slow and controlled rate to prevent damage to the new or repaired refractory. During periods of low rate and low temperature operation, CO emissions will be high.

Response: See the preamble for response to how EPA adjusted CO emission limits and compliance mechanisms, and changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 89

Comment: Even for boilers and process heaters with extensive controls, the controls will be ineffective during startup and shutdown period and possibly during turndown periods. For instance;

* Oxidation catalyst is ineffective at reducing CO or dioxin/furans during such operations due to low stack temperatures.

* A fabric filter (FF) cannot be put into service until the flue gas temperature is above the dew point. This requires that all heat transfer surfaces, ducts and flues from the combustion zone to the FF inlet be warmed up from ambient temperatures to dew point temperature (which varies by fuel type and fuel constituents, but is typically in excess of 140 degree F). It takes a considerable amount of time, typically several hours for larger units, to warm up this considerable mass of steel: waterwall tubes, superheater tubes, reheater tubes, economizer tubes, casings, turning vanes, air preheaters, ducts and inlet plenums. During this warm-up period, the FF cannot be put into service without risking catastrophic failure of the bags and intensive corrosion damage to the FF.

* Electrostatic precipitators (ESPs) must typically warm-up to be effective. Premature starting of this equipment will lead to short term stability problems that could result in unsafe actions and longer term degradation of ESP performance due to fouling, increased chances of wire damage or increased corrosion within the chambers.

* Units equipped with spray dryer absorbers (SDA) for acid gas removal are limited in the amount of reagent slurry that can be injected into the flue gas during startup. The slurry federate is limited due to the nature of the technology by the amount of moisture the flue gas can evaporate. This in turn requires that a minimum temperature be achieved by the flue gas before the slurry federate can be initiated, and imposes a lengthy period of time during which the slurry federate is significantly limited until all the upstream heat transfer surface and ductwork has been warmed up. As such, SDA cannot remove hydrogen chloride in significant quantities for several hours after the unit is first fired.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 90

Comment: If CO levels average 30 ppm for even one day during a turndown, start-up or shutdown, the 30 day average will be exceeded for the subsequent 30 days that include the 30 ppm day. Thirty- day averages have been used in several rulemakings to address combustion emission variability. However, in essentially all of these rulemakings, turndown, startup and shutdown periods have been excluded from those 30-day averages. Arbitrarily including them in this proposal doesn‘t address their impact. Extending the averaging period to a 365-day average would help address the impact of incorporating these periods into the compliance averages, but such a long averaging period introduces other concerns and, as we discussed, measurements during these periods are generally infeasible in any case. Thus, addressing turndown, startup and shutdown through the 112(h) provisions makes the most sense.

Response: See the preamble for response to how EPA adjusted CO emission limits and compliance mechanisms, and changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 91

Comment: For pollutants other than CO, there is less information on how their controls behave during turndown, start-up and shutdown, but, since those are inherently periods of poor combustion and unstable operation, we would expect there to be exceedances. For instance, the temperature of the stack gas going into the activated carbon absorption system will vary from ideal during startup and shutdown operations thus, mercury and dioxin removal will be less efficient than during normal operations.

We note that this issue is recognized in many permits and regulations. For instance, one member site reports that their permit allows 36 hours for refractory curing and 12 hours for normal startups and shutdowns as long as firing stays under 75% of design. During this time, NOx and CO concentration limits do not apply, but max lb/hr and T/yr limits still apply. Other special situations, where permits and/or regulations allow exceptions from certain limits include maintenance outages of forced air and air preheat systems. For instance, the Texas NOx RACT rule recognizes NOx limits will not be met during low firing rates and the Part 60 combustion rules (NSPS subpart D rules) exclude startup and shutdown from compliance averages for NOx.

Since it is not feasible for boilers or process heaters to meet all of the emission limits during turndown or certain startups and shutdowns, work practice requirements should be specified for these startups as provided for in 112(h). We recommend a startup and shutdown plan work practice along the lines of the Part 63 SS&M plan, for startups and shutdowns, and that turndown operations be addressed as they are in the GACT proposal, by not including such periods in the compliance averages.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 92

Comment: Applying the emission limits during startups will encourage sources to try to shorten the startup period. Reductions in the amount of time required to warm the boiler or process heater up could be realized by increasing the ramp-rate of adding fuel to the unit. In theory, a boiler or process heater could be brought from first flame to full load in a matter of minutes, but decreasing the warm-up period from what the manufacturer‘s recommendations risks severe metallurgical and refractory stresses due to rapid changes in temperature and wide variances in temperatures across the unit and duct parts. Immediate failures could occur if inconsistent heating caused tears or ruptures in support steel or heat transfer surfaces, posing considerable risk to personnel in the plant. Failure rates would also increase due to the considerable stresses introduced by rapid heating and cooling cycles, yielding failures at unpredictable times (steady state operation or future startups or shutdowns). For this reason, OEM recommendations for startup times are closely followed across industry.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 93

Comment: A work practices approach for these periods also would be consistent with EPA's recently promulgated MACT standards for compression ignition reciprocating internal combustion engines (CI-RICE) [Footnote: 75 FR 9648 (Mar. 3, 2010)]. Based on comments received from stakeholders, EPA finalized work practice standards for startup because the agency determined that it was "not feasible to finalize numerical emission standards that would apply during startup because the application of measurement methodology to this operation is not practicable due to technological and economic limitations." [Footnote: 75 FR 9648 (Mar. 3, 2010) at 9656.] According to EPA, applicable test methods that would be needed to measure during these events "do not respond adequately to the relatively short term and highly variable exhaust gas characteristics occurring during these periods." [Footnote: 75 FR 9648 (Mar. 3, 2010) at 9665.] Furthermore, EPA determined that the cost for testing all the engines affected by the rule to get the necessary data could be more than $1 billion. [Footnote: 75 FR 9648 (Mar. 3, 2010) at 9665.] Startup and shutdown periods for boilers encounter similar testing challenges and costs.

Recommendation: Provide work practice requirements for start-up and shutdown situations where emission limits cannot be met and exclude CO CEMS measurements during periods of turndown from compliance averages.

Response: See the preamble for response to how EPA adjusted CO emission limits and compliance mechanisms, and changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-2702.1
Comment Excerpt Number: 105

Comment: Opacity limit of 10% on a daily block average will not be adequate to allow operation during SSM periods.
As recommended elsewhere in these comments, CIBO recommends that startup and shutdown periods be handled using a work practice standard. Limiting opacity to 10% on a daily block average may be appropriate for normal operation, but it will not allow startup and shutdown operations to proceed, since there is simply not enough time to average out to such a low limit.

Use of startup and shutdown work practice with a prescribed plan is an appropriate approach that can be tailored to the specific unit. A similar approach needs to be provided for malfunctions so that actions can proceed in an orderly and safe manner to address malfunctions.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-2702.1
Comment Excerpt Number: 124

Comment: a. SSM periods should be handled as awork practice
Even with use of a 30 day rolling average for PM CEMS, that is not adequate to cover SSM periods, and the emissions data used to establish the emission limits does not include SSM periods. CIBO recommends that SS and M periods be handled with a work practice approach.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 133

Comment: The Coen emissions guarantees are not valid below 25% load. This is due to the higher levels of excess air at low loads that result from the minimum airflow levels required by NFPA. In addition, Coen noted that CO emissions during a cold startup would be significant due to the reduced temperatures of the boiler heat recovery surfaces. Under these conditions, unburned fuel that comes into contact with the cold surfaces will smolder (instead of combusting completely), and will form significant amounts of CO. Coen noted that CO emissions during a cold startup could average several hundred ppm for the first hour or more. This is more than enough to cause the 30-day rolling average to exceed the proposed limit for all 30 days including that startup hour.

Response: See the preamble for response to how EPA adjusted CO emission limits and compliance mechanisms, and changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 137

Comment: CO will vary significantly, even for the best performing units, because of operating variability, startup and shutdown operation, turndown operation, and burner outages for tune-up inspections or maintenance, among other reasons. CO will typical spike to several hundred ppm as a result of these activities and adjustments will take some time. A 1 or 2 ppm emission limit provides little leeway for such normal variations, even with a 30 day averaging time. The following chart shows the hours of an elevated CO value can occur to cause a deviation. Given the difficulty in measuring CO in the low ppm range and the common occurrence of CO spikes, a 1 or 2 ppm limit will frequently be exceeded, simply because of measurement variability and the normal variability or startup, shutdown or turndown activity.
[See submittal for graph of allowable excursions for 1 ppm monthly average CO]

Recommendation: Address normal CO operating and measurement variability in establishing any low ppm CO emission limit.

Response: See the preamble for response to how EPA adjusted CO emission limits and compliance mechanisms, and changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-2702.1
Comment Excerpt Number: 178

Comment: Start-up, Shut-down, Malfunction
EPA is proposing that the emissions standards it has established in this rule apply during both normal operations and periods of startup, shutdown and malfunction (SSM). CIBO strongly disagrees with this approach, believing it is inappropriate to require compliance with emissions standards that are achievable during periods of steady-state operation during periods of startup and shutdown. CIBO also believes that affected sources may be unable to comply with the standards during SSM periods, and therefore the proposed standards are contrary to the CAA’s requirement that standards established under Section 112(d) be "achievable." See 42 U.S.C. § 7412(d)(2). According to the D.C. Circuit, this when "achievable" means "under the most adverse conditions which can reasonably be expected to recur." National Lime Ass’n v. EPA, 627 F.2d 416 (D.C. Cir. 1980). If sources cannot meet the proposed emissions standards during "routine" periods of startup and shutdown, nor during adverse periods of malfunction, the proposed standards are therefore not "achievable," and thus not compliant with the Act.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-2702.1
Comment Excerpt Number: 179

Comment: A. EPA Asserts without Support that CEMs Data includes SSM Periods.
To support its conclusion that the proposed emission standards are achievable during all operational periods, including during SSM events, EPA asserts that startup and shutdown emissions replicate normal operation emissions. These conclusions are not supported by the record. EPA relied on continuous emission monitoring (CEMs) data obtained from best performing units, which EPA claims included periods of startup and shutdown. It is unclear to CIBO whether this CEMs data actually warrants these conclusions. First, it does not appear that any of the units considered in the data collection were in startup or shutdown during the 30-day period of testing that EPA looked at. If that is the case, then the CEMs data gives no bearing on whether units can satisfy emissions limits over a 30-day period if all startup and shutdown events are included.

Additionally, EPA is operating on the assumption that "[b]oilers, especially solid fuel fired boilers, do not normally start up and shutdown more than once per day[,]" and that "startup and shutdown are part of [boilers'] routine operations and, therefore, are already addressed by the standards." 75 FR at 32,012. These are not accurate conclusions for many boilers, as circumstances may necessitate multiple startups and shutdowns throughout a day, and additionally, that a boiler may routinely need to start up and shut down does not mean the emissions from those events are the same as the emissions during steady-state operation. Further, the CAA has been interpreted to require that emissions standards be achievable under the most adverse conditions that can be expected to occur, not under assumptions of what is normally done or not done. EPA has not show that it actually considered startup and shutdown periods even though it is proposing to implement emissions standards that should apply to units during steady-state operations as well as such periods.

Another concern that CIBO has is that EPA used 3-run stack test data, and not 30-day data, to set the proposed emissions floors. EPA uses test run data collected through the ICR phase II testing process – which reflect normal, often steady state, operating conditions – to set proposed floors. Even EPA's docket materials in support of the Proposed Rule acknowledge that this data fails to account for the dynamic conditions and variable emissions occurring during startup and shutdown episodes. Further, this data does not make use of the CEMs data (with the startup and shutdown information) in its variability analysis, which is where it would be the most helpful in reflecting real-world fluctuations in emissions.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-2702.1
Comment Excerpt Number: 180

Comment: Requiring Emissions Controls during SSM is Not Technically Feasible.
The current decision by EPA to 'eliminate' omission of startup, shutdown, and malfunction emissions records is not only 'short sighted' but technically unjustified. A series of previous emission control programs over the last twenty-five years has resulted in the installation of several 'systems' to achieve specific emission reductions through targeted technologies, but most are designed for 'steady state' or 'normal operations'.

The first of these was implemented under the CAA revision of 1990 that required units larger than 25 MWe to reduce sulfur emissions below 1.2 lb/MMBtu and achieve at least a 90% reduction. One of the few methods of doing this that could survive severe abrasive characteristics present in some units was dry limestone injection. This process is dependent on injection of 'sized' limestone into the furnace/boiler, calcinations of the limestone, and subsequent absorption of sulfur present in the flue gas. This process 'begins to occur' at a useful rate at about 860 deg. F and is 'functional' up to about 2200 deg. F. (Unfortunately at about 1640 deg. F thermal NOx generation normally inhibits operation above that temperature.) For a boiler to achieve the lower useful temperature of 860 deg. F, it must be 'heated up' to that level, generally using natural gas or fuel oil. This 'thermal change' to the materials that boilers are fabricated with, is limited by impacts of thermal stresses placed on both the generating tubes and drum materials, by the manufacturers to a change rate of 100 deg. F. Thus, to take a unit from 'cold' to the functional temperature that limestone becomes effective for SO2 removal, takes a minimum of about eight to ten hours. Application of 'normal steady state' limits based on a temperature of 1600 deg. makes no sense. Due to the high volume of combustion air involved, most 'casualties result in the unit falling outside of the optimum band for absorption also, so application of the limits during these periods is short sighted, as it is technically unfeasible to attain them.

A similar situation exists with respect to NOx. Many facilities were 'swept' into further NOx reduction under the 'NOx Budget Program' in the late 1990's. To meet these requirements, most installed a Selective Non-Catalytic Removal system, which injects ammonia or urea into the combustion gas stream and results in much of the NOx present there becoming a 'solid' and mixing into the ash residue from combustion. This process occurs at a meaningful level at temperatures above 1200 deg. F up to about 1650 deg. F. The same 'heat-up' limits apply for cold plant startup, as well as casualty impact as listed above.

A second '1990' requirement resulted in baghouse installation instead of electrostatic precipitators for any new installations. Unfortunately, for many of these units the baghouses were unable to withstand the 'gas stream temperature' when they were heated up to operating temperature with gas or fuel oil burners, as the 'bags' in them were limited to temperatures less than 350 deg. F. but greater than 150 deg. to avoid water formation/plugs in the ash and air stream. The high end could not be maintained with limited combustion air heater flow until the units temperature approached about 800 deg. F during the heat up, while the lower end was present until achieving at least 300 deg. during the heat up. A ‘baghouse’ bypass was installed for that purpose, although not used at any other time. Currently ‘some’ bag vendors have developed replacements that can withstand a higher temperature and are more resistant to casualty situations, but not all of them.

All of the above are functional in reverse during a shutdown. Other types of ‘emissions removal’ (e.g., SCR) also require specific ‘thermal inlet’ temperatures to function that cannot be maintained during either startup, shutdown, or during specific malfunctions.

Lastly, many CEM units are ‘calibrated’ to operate at specific stack temperatures associated with ‘normal operations’. During ‘thermal cycles’ of the unit, it is doubtful that any of the CEMs maintain required accuracy much less record actual ‘emissions.’ It is likely that the only trustworthy data is opacity during SSM as most of the other instruments may provide an output, but nothing in the current regimen of testing assures its accuracy.

EPA has long recognized that control and/or monitoring equipment is not necessarily functional during SSM periods. In developing the SSM approach in the General Provisions, EPA recognized the "difficulty of determining compliance" during SSM periods. 58 FR 42,777 (Aug. 11, 1993). EPA adopted an approach whereby an owner of an affected facility who abides by a valid SSM plan during SSM periods would not be deemed in violation of the applicable standard. EPA stated:

This approach carries forward the requirement that control systems be operated at all times, but it allows special situations to occur, such as unpredicted and reasonably unavoidable failures of air pollution control systems, when it is technically impossible to properly operate these systems. 58 FR 42,777 (Aug. 11, 1993).

In the preamble to the final General Provisions, EPA responded to one commenter who said EPA should require affected sources to meet otherwise applicable emission limits during startups, shutdowns, and malfunctions. EPA said it "believes, as it did at proposal, that the requirement for a startup, shutdown, and malfunction plan is a reasonable bridge between the difficulty associated with determining compliance with an emission standard during these events and a blanket exemption from emission limits." 59 FR 12,423 (Mar. 16, 1994). We believe EPA’s rationale applies to affected sources subject to the Boiler MACT standards and we fully support retaining this approach to startup, shutdown and malfunction in the final regulations.

Response: See the preamble for achievability of limits, and changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-2702.1
Comment Excerpt Number: 181

Comment: C. An Extended Averaging Period Will Not Eliminate Problems With Making Emissions Limits Applicable During Startup and Shutdown Periods.
Institutional, commercial and industrial boilers, require an extended period of startup lasting several hours (e.g. gas, liquid, or solid fuel boilers) or days (e.g. large circulating fluidized bed boilers). During the required startup periods, most, if not all, equipment in the boiler and pollution control systems are not operating in their normal condition. Consequently, pollutant emission concentrations and emission rates can exceed those experienced during normal operation. It is very common in the boiler industry for certain control devices to be out of operation during periods of startup due to the nature of the equipment. During such periods it is likely that emissions will exceed the standards proposed and would never be able to recover to meet the average limitations. (See below for a more expanded discussion with respect to a few specific technologies). This extended startup period, ranging from several hours to a few days for some specific units, is required due to equipment integrity concerns, limitations of the technologies, or safety concerns:

Equipment Integrity – For example, a Fabric Filter (FF) cannot be put into service until the flue gas temperature is above the dewpoint. This requires that all heat transfer surfaces, ducts and flues from the combustion zone to the FF inlet be warmed up from ambient temperatures to dewpoint temperature (which varies by fuel type and fuel constituents, but is typically in excess of 140°F /60°C). It takes a considerable amount of time, typically several hours for larger units, to warm up this considerable mass of steel: waterwall tubes, superheater tubes, reheater tubes, economizer tubes, casings, turning vanes, air preheaters, ducts and inlet plenums. During this warmup period, the FF cannot be put into service without risking catastrophic failure of the bags and intensive corrosion damage to the FF. This limits a unit's ability to control Particulate Matter and Mercury during the several hours of startup.

Limitations of the Technology – For example, units equipped with a Spray Dryer Absorber (SDA) for acid gas removal are limited in the amount of reagent slurry that can be injected into the flue gas during startup. The slurry federate is limited due to the nature of the technology by the amount of moisture the flue gas can evaporate. This in turn requires that a minimum temperature be achieved by the flue gas before the slurry federate can be initiated, and imposes a lengthy period of time during which the slurry federate is significantly limited until all the upstream heat transfer surface and ductwork has been warmed up. As such, SDA cannot remove Hydrogen Chloride in significant quantities for several hours after the unit is first fired.

Safety Concerns – For example, reductions in the amount of time required to warm the boiler system up could be realized by increasing the ramp-rate of adding fuel to the unit. In theory, a boiler could be brought from first flame to full load in a matter of minutes, but decreasing the warm-up period from what the OEM recommends risks severe metallurgical stresses due to rapid changes in temperature and wide variances in temperatures across boiler and duct parts. Immediate failures could occur if inconsistent heating caused tears or ruptures in support steel or heat transfer surfaces, posing considerable risk to personnel in the plant. Failure rates would also increase due to the considerable stresses introduced by rapid heating and cooling cycles, yielding failures at unpredictable times (steady state operation or future startups or shutdowns). For this reason, OEM recommendations for startup times are closely followed across industry.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-2702.1
Comment Excerpt Number: 182

Comment: EPA makes a mistaken assumption that startups and shutdowns are "predictable and routine." 75 FR at 32,012. Industrial facilities, unlike electric utilities, typically operate a large number of smaller units of varying ages instead of operating a small number of very large units. When normal equipment failure rates (e.g., tube leaks) are multiplied across a large number of units, the total number of unit failures can be significantly larger at industrial facilities. One member company operates a facility with over a dozen boilers, which average more than two unplanned outages per unit above and beyond each unit’s planned outage in a any given year. It is not uncommon for unplanned outages to occur in clusters, such as when a given component (e.g., an economizer) might suffer a failure due to corrosion or erosion. Repairs may fix the failure at identified vulnerable areas nearby, but the root cause of the failure could be occurring in multiple areas that are not easily identified, resulting in additional failures in a short timeframe.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-2702.1
Comment Excerpt Number: 183

Comment: EPA seeks to address the fact that units will not be able to comply with the proposed emissions standards by during startups and shutdowns by proposing extended (daily or monthly) averaging periods. The assumption that longer averaging periods will provide a reasonable method to ensure compliance is likewise flawed. Startup and shutdown periods vary in duration and intensity, a fact that can significantly impact actual emission profiles. Additionally, because unplanned outages are a reality in the operation of any boiler, industrial or utility, and because unplanned outages are by their nature unpredictable, unplanned shutdowns can and will cluster together. For example as shown by the table (see submitted for example emission data), if a unit firing eastern bituminous coal equipped with a Spray Dryer Absorber for acid gas control were to have two unplanned outages in the month following startup from a planned shutdown, the calculation of a 30-day average fails to prevent a deviation from the HCl standard:

Such a scenario would result in a unit being out of compliance because EPA inappropriately failed to craft a compliance protocol to address the fact that emissions performance during startups and shutdowns is necessarily not equivalent to emissions performance during steady-state operation.

Extended averaging periods are similarly inadequate to provide a reasonable method to demonstrate compliance with the CO standard, due to the inherent variability of CO in solid fuel boilers across the load range, but especially upon startup. See the figure below showing CO data from a coal stoker fired boiler that monitors CO via CEMS. It is readily apparent that CO emissions during normal startup conditions can be two orders of magnitude above the proposed standard of 50 ppm for stoker boilers. (See submittal for coal stoker fired boiler carbon monoxide during startup figure.)

This table (see submittal for table of CO emissions) demonstrates the impact of the startup of this unit on the calculation of a 30-day average.

This data set illustrates the impact of a typical unit startup on a calculated 30 day average and the problem with requiring a unit to comply with a steady-state emission standard during startups and shutdowns. Had this unit been subject to the standard proposed in this rule, the source would have been out of compliance due to the two calendar days that saw startup activities, despite the fact that the source was operated near or below the proposed standard for CO the following 40 days.

Response: See the preamble for response to how EPA adjusted CO emission limits and compliance mechanisms, and changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-2702.1
Comment Excerpt Number: 184

Comment: Instead of relying on extended averaging periods, EPA should instead provide additional provisions to ensure emissions are minimized during startups and shutdowns without unreasonably requiring sources to attempt to comply with steady-state emission standards. EPA should add provisions to require sources to develop and adhere to operating practices specific to the unit's design, fuel type, and OEM recommendations that will ensure emissions minimization without forcing owner/operators to choose between putting their equipment integrity and personnel safety at risk versus failing to comply with this rule. Such an operating practice should be crafted to be flexible, given the wide variety of boiler sizes, types, vintages, and fuels fired, and should be developed by the source based on OEM recommendations. General guidelines could include:

* Sequencing of equipment startups, per OEM recommendations;
* Startup time durations, per OEM recommendations, and
* Provisions to clearly define what constitutes "online" versus "startup". This could be crafted to mean a percentage of the unit's maximum continuous rating, or steam temperature/pressure, etc.

CIBO notes that EPA followed this approach in its final rule for Reciprocating Internal Combustion Engines (RICE) issued on March 3, 2010. There, EPA concluded "it was not feasible to prescribe a numerical emission standard for stationary CI engines during periods of startup because the application of measurement methodology to these engines is not practicable due to the technological and economic limitations described below." 75 FR 9665. Many of the reasons EPA articulates for this decision apply to the boiler and process heater source category regarding the accuracy of the stack gas sampling methods during transient load cases like startup. Eastman recognizes that EPA has set work practice standards in the RICE rule by limiting startups to 30 minutes. We agree this is appropriate. However, when it comes to boilers and process heaters, it is a much more complicated issue. Given the variety of units, operating pressures and temperatures, etc., we do not believe it is practical to set startup and shutdown periods on a "one-size fits all" basis. Rather, each source should work with their permitting authority to establish and obtain approval of appropriate work practice standards as we discuss above.

CIBO proposes two solutions to fix the deficiencies in the Proposed Rule relative to startup/shutdown emissions expectations. First, CIBO proposes that EPA should use operating practices during startup and shutdown to include general content relative to specific startup and shutdown sequences and time limits pending meeting emissions limits. Alternatively, if EPA uses a startup/shutdown standard, EPA should establish an averaging period that accounts for a wide range of emissions from startup and shutdown.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-2702.1
Comment Excerpt Number: 185

Comment: d. Malfunction Periods Not Account for in Floor Setting.
The Proposed Rule also expects that the emissions standards applicable during normal operations must also be met during periods of malfunction. This expectation directly conflicts with the statutory requirement that EPA set MACT standards that are "achievable" since even the best performers will experience malfunctions that may result in those sources not meeting the proposed standards. CIBO is also concerned that compliance with the emissions standards during

malfunction events will be difficult to gauge since emissions testing during such events is near impossible given the sporadic and unpredictable nature of malfunctions.

Another concern is that the Proposed Rule could force units to choose between safety and compliance with emissions requirements. For some affected units, malfunctions by their very nature create unsafe conditions which can lead to excessive combustible mixtures in a furnace that can result in explosions, equipment damage and personnel hazards.

Response: See the preamble changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-2702.1
Comment Excerpt Number: 186

Comment: CIBO proposes that EPA set work practice requirements based on maintenance plans established by each source. Such plans should be expected to address how to expeditiously deal with malfunctions in a way that balances the desire to most efficiently minimize emissions while also maximizing safety responses and expeditiously resolving malfunction events. While the Sierra Club court ruled that sources cannot be exempt from complying with MACT standards, the court noted that Congress recognized in some instances that it may not be feasible to prescribe or enforce an emission standard under Section 112. See Sierra Club v. EPA, 551 F.3d at 1028. In such limited circumstances, section 112(h) "work practices" or "operational" standards are available. Id.

Section 112(h) allows the Administrator to promulgate a design, equipment, work practice, or operational standard, or combination thereof, in lieu of an emission standard where it is not feasible to prescribe or enforce an emission standard. 42 U.S.C. § 7412(h). Infeasibility exists where "a hazardous air pollutant or pollutants cannot be emitted through a conveyance designed and constructed to emit or capture such pollutant,’ or "the application of measurement methodology to a particular class of sources is not practicable due to technological and economic limitations." Id. Because of the difficulty of obtaining emissions data during malfunction periods, and the substantial variety of circumstances that may manifest during malfunction events, it would be difficult and impractical and infeasible for EPA to craft emissions standards for application during both malfunction periods and normal operations. Thus, CIBO believes that the best approach is not to continue with the present proposal of applying the same standards EPA has set for normal operations to malfunction events, but rather, for EPA to use § 112(h) to set work practice standards that would allow facilities to establish source-appropriate procedures during malfunctions. Such procedures would enable sources to maintain safe practices while addressing the malfunction and implementing procedures to minimize emissions during any such event.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-2702.1
Comment Excerpt Number: 187

Comment: EPA states in the Proposed Rule that if a source fails to comply with the applicable standard due to a malfunction, EPA "would determine an appropriate response." 75 FR 32013. Many large sources have been required to submit "Standard Operation and Casualty Procedures" under Title V concerning time limitations of malfunctions that impact emissions. These procedures were based on not exceeding monthly averages in the permit. Furthermore, the definition for "malfunctions" appears to be inappropriate considering that many malfunctions occur due to component failure and have nothing to do with "poor maintenance or careless operation" as defined in 40 C.F.R. § 63.2. Congress acknowledged that malfunctions cannot be prevented, and provisions allow for such occurrences. [CITE] EPA also acknowledges that malfunctions cannot be prevented, even by top performers, and therefore defines the regulations at 40 C.F.R. at § 60.2. EPA unreasonably proposes all sources to comply with standards established for steady-state operation during periods of malfunction. This approach inappropriately fails to include provisions that take into account the unpredictable nature of malfunctions, and that malfunctions occur to all units including top performers.

EPA should include additional provisions to accommodate the unpredictable and unavoidable malfunctions that both Congress and EPA acknowledged would occur. EPA should adopt a work practice of requiring malfunction plans to address potential equipment failures, provide troubleshooting and corrective actions, and other reasonable measures so to minimize the duration of malfunctions and minimize emissions during unavoidable malfunctions. Using the plan and documenting actions in accordance with the plan would then constitute minimizing emissions via the general duty clause.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 42

Comment: The database does not contain any data for low rate, special operations, or startup and shutdown operations though emission limits are proposed to apply to these operations. Very little data is included for operating conditions other than those at the high firing rates typically required for performance tests. Nothing is included in the available information to demonstrate that the fuels fired when emissions data were collected are typical for the source category or even for that particular unit.

Response: See the preamble for achievability of limits and changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Robert E. McKenna
Commenter Affiliation: Motor and Equipment Manufacturers Association
Document Control Number: EPA-HQ-OAR-2002-0058-2778.1
Comment Excerpt Number: 10

Comment: EPA's analysis failed to properly address the variability of the data, as well as emissions associated with startup, shutdown and malfunction. Thus, EPA's proposed limits do not appropriately address the variability in emissions of various HAPs.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Leslie Sue Ritts
Commenter Affiliation: National Environmental Development Association's Clean Air Project NEDA/CAP
Document Control Number: EPA-HQ-OAR-2002-0058-2794.1
Comment Excerpt Number: 8

Comment: Contrary to statements in the preamble for the proposed standards, EPA does not appear to have considered data from start-ups and shutdowns in its floor analysis.

The proposed rule is deficient because it lacks specific start-up, shutdown, and malfunction emission standards or work practice standards for boilers, although the Agency argues that it considered SSM emissions in establishing the floors for the proposed standards. For instance, EPA insists that SSM events are included because the emission limits are based on continuous emission monitoring data:

"The standards that we are proposing are daily or monthly averages. Continuous emission monitoring data obtained from best performing units and used in establishing the standards, include periods of startup and shutdown. Boilers, especially solid fuel fired boilers, do not normally startup and shutdown more than once per day. Thus, we are not establishing separate emission standards for these periods because startup and shutdown are part of their routine operations and, therefore, are already addressed by the standards."

at 32,012-13. In this discussion, EPA also asserts that startup and shutdown are part of “routine operations” and are therefore “already addressed” in the MACT standards. EPA’s docket materials do not support these statements.

In establishing proposed MACT limits, EPA clearly did not rely on the CEMs data when setting the floors for boilers and process heaters. To the contrary, as indicated by the MACT floor memo, EPA uses test run data collected through the ICR phase II testing process, which reflect normal (often steady state) operating conditions, to set the proposed floors. Thus, according to EPA’s own docket materials, the data used to set the proposed floors fail to account for the dynamic conditions and variable emissions occurring during startup and shutdown episodes. Furthermore, as the MACT floor memo makes abundantly clear, EPA’s approach does not make use of the CEMs data (with the startup and shutdown data) in its variability analysis where it would be the most helpful in reflecting real world fluctuations in emissions.

Response: See the preamble for discussion of MACT floor methodologies, and changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: H. Allen Faulkner
Commenter Affiliation: Ascend Performance Materials, LLC
Document Control Number: EPA-HQ-OAR-2002-0058-2743.1
Comment Excerpt Number: 1

Comment: Ascend operates three coal fired boilers at its Decatur site that will be required to meet the emission limits set forth in the Boiler MACT rule. The site uses electrostatic precipitators (ESP) for particulate matter (PM) emission control on all of the units. During normal startups of these units, the ESP cannot be initiated until that unit reaches a specified operating temperature, per its design parameters. As a result, it takes, typically 4 hours, from initial startup of a coal fired unit to the startup of pollution control equipment, which means that the emission limit cannot be met on the unit, even with time weighted averaging of the emissions. Ascend requests that EPA consider an alternative approach for the startup and shutdown emission limits, such as work practice standards.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Dale A. Riddle
Commenter Affiliation: Seneca Sustainable Energy
Document Control Number: EPA-HQ-OAR-2002-0058-2866.1
Comment Excerpt Number: 2

Comment: During the shutdown process and subsequent startup (six to eight hours), it may be impossible to meet the literal CO limits contained in the proposed rules.

In order to safely start up a biomass boiler without risk of causing explosion and avoid undue stress to the boiler, it is necessary to heat up the boiler slowly and without the benefit of particulate controls. EPA has recognized that until combustion is stable and the boiler has reached an exhaust temperature of 250F, it is not safe to energize an ESP. This fact has been recognized in prior rules such as the Boiler NSPS. In the proposed rule, EPA grants no recognition of the realities of biomass boiler startups, imposing the standards applicable to normal operation to days where startups occur. The only recognition of the anomalous conditions that exist during startup was to state that 24-hour averaging would enable boiler operators to demonstrate compliance notwithstanding startup. This is grossly inaccurate. Startups can routinely take six to eight hours and opacity readings (although not necessarily accurate as recorded by a continuous opacity meter), can reach 90 percent. It is well known that initial opacity readings do not reflect actual opacity as considerable moisture is driven off the kindling fuel and the interior surfaces of the boiler resulting in water vapor that is inaccurately read as opacity. However, there is also significant opacity during startup that is not capable of being reduced as the control equipment cannot be energized until the moisture is driven off and the interior surfaces adequately warmed up. Rushing this process can result in damage to control equipment and explosion concerns. As a result, notwithstanding good operation, it is probably mathematically impossible to average the startup opacity conditions with the opacity once normal operations have commenced to comply with a 10 percent opacity standard applicable to those biomass boilers employing ESPs or scrubbers (the vast majority of the controlled boilers in this subcategory).

Response: See the preamble for response to how EPA adjusted CO emission limits and compliance mechanisms, and changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Jeffrey R.Klieve
Commenter Affiliation: Monsanto Company
Document Control Number: EPA-HQ-OAR-2002-0058-2754.1
Comment Excerpt Number: 2

Comment: Table 2 of the proposed rule lists the CO emission limitations for Gas 2 boilers and process heaters at 1 ppmv dry basis corrected to 3% 02 on a 30-day rolling average for units 100 MMBtu/hr or greater; 3-run average for units less than 100 MMBtu/hr. However, USEP A has not established different emission limitations for periods of boiler startups, shutdowns and malfunctions, stating that emissions during these events are taken into consideration in the averaging times of the proposed standards. Monsanto operates a gas-fired boiler with a CO CEMS and the unit generally operates below the proposed 1 ppm standard. In review of historical CO CEMS data during typical startups and shutdowns for this boiler, we found that the 30-day rolling average may exceed the proposed standard by as much as 70%. Startup times would be longer during cold startups or when repairs have been completed, such as replacement of refractories in the boiler. Therefore, the proposed concentration level combined with the long averaging time for the CO standard is not adequate to cover startup and shutdown events, either planned or unplanned.

This approach is inconsistent with the General NESHAP Provisions found at 40 CFR 63.6(e):

... The general duty to minimize emissions during a period of startup, shutdown, or malfunction does not require the owner or operator to achieve emission levels that would be required by the applicable standard at other times if this is not consistent with safety and good air pollution control practices …

Response: See the preamble for response to how EPA adjusted CO emission limits and compliance mechanisms, and changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Jeffrey R.Klieve
Commenter Affiliation: Monsanto Company
Document Control Number: EPA-HQ-OAR-2002-0058-2754.1
Comment Excerpt Number: 3

Comment: Monsanto is also concerned that a concentration-based standard during startup and shutdown periods does not appear to be valid. Since the firing rate during these periods is much lower than typical values, the actual mass flow of CO emitted at a specific CO concentration is also much lower than during typical operating periods. In other words, the actual CO emissions can very well be lower during these periods, but the rule as proposed, would not take this into account.

Accordingly, Monsanto requests that USEPA revisit this treatment of SSM events and either treat them in a manner consistent with 40 CFR 63(e), or provide a higher limit for certain pollutants during such events.

Response: See the preamble for response to how EPA adjusted CO emission limits and compliance mechanisms, and changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Michael J. Nasi
Commenter Affiliation: Gulf Coast Lignite Coalition
Document Control Number: EPA-HQ-OAR-2002-0058-2800.1
Comment Excerpt Number: 3

Comment: EPA’ s inclusion of startup shutdown emissions in the emission standards creates unattainable and inflexible standards in conflict with prior guidance.

In 2008, the U.S. Court of Appeals for the D.C. Circuit vacated the EPA's exemption from CAA Section 112 requirements for 'Hazardous Air Pollutant (HAP) emissions during periods or startup, shutdown, and malfunction (SSM). [Footnote: Sierra Club v. EPA, 551 F.3d 1019 (DC Cir. 2008), cert. denied, 2010 U.S. LEXIS 2265 (2010).] In light of the decision, EPA issued guidance in 2000 addressing SSM emissions for a variety of sources, recognizing that emission standards under (Clean Air Act Section 112(d) should be attainable as they are expressed as an average over a relatively long period of time (e.g., yearly). [Footnote: 75 FR at 32025 (June 2, 2010).] Also. the "EPA will give highest priority to reviewing, and revising those Section 112(d) source category standards that may be difficult for sources to meet during an SSM period given the technological limitations of the processes involved. [Footnote: See July 22, 2009 EPA letter Re: Vacatur of Startup, Shutdown, and Malfunction Exemption, available at <http://www.epa.gov/oecaerth/civil/caa/ssm-memo080409.pdf>.]

The EPA must not deviate from the guidance language since the vacatur of the SSM exemption. Where before emission standards averaged over a year were viewed as attainable, here the EPA is stating that the proposed emission standards averaged over a day or month are attainable. [Footnote: 75 Fed.Reg. at 32013.] Further. EPA previously recognized in the guidance letter that sources will require some flexibility due to technological limitations. The industrial Boiler NESHAP preamble does not afford the same recognition of for technological limitations. [Footnote: 75 Fed.Reg. at 32012. "[EPA is] not establishing a separate emission standard for these periods because startup and shutdown are part of their routine operations and , therefore, are already addressed by the standards.] EPA creates a discrepancy in the application of the NESHAP based on fuel choice by requiring emission standards tilt some boilers, which include highly variable emissions during startup and shutdown periods averaged over a fairly short time period.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Dale A. Riddle
Commenter Affiliation: Seneca Sustainable Energy
Document Control Number: EPA-HQ-OAR-2002-0058-2866.1
Comment Excerpt Number: 3

Comment: We strongly encourage EPA to develop an exception to compliance with the work practice standards. Other recently promulgated NESHAPs have recognized that it is impossible to demonstrate compliance with emission standards during startup conditions and have allowed sources a reasonable period where they do not need to demonstrate compliance with the limits. For example, the Subpart ZZZZ NESHAP allows natural gas and diesel-fired engines a startup period during which the standards do not apply. If this can be allowed for fossil-fuel-fired units such as reciprocating internal combustion engines, a similar approach should be recognized for biomass boilers. Therefore, we recommend that EPA revise the rules to allow an eight-hour startup period during which the limits do not apply. Because this time may not be adequate for startup of some larger boilers without any supplementary fuel capability, we also suggest that EPA clarify that sources can apply to EPA for a longer startup time period.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: J. Michael Geers
Commenter Affiliation: Duke Energy
Document Control Number: EPA-HQ-OAR-2002-0058-2765.1
Comment Excerpt Number: 3

Comment: Duke Energy urges EPA to use its authority under the CAA Sections 112 (d) (h) and 111 to provide a work practice operational standard to address HAP emissions during startup and shutdown in lieu of a numerical limit.
HAP emissions during startup and shutdown ("SU/SD") should not be treated the same as HAP emissions during normal operations. EPA has not established a basis to conclude that SU/SD emissions of HAP are the same as during normal operations. Setting the same standard for SU/SD and normal operations will result in an unattainable standard for the owner/operator despite the application of MACT controls. In setting MACT standards, EPA must properly characterize the entire range of operation of the units used to determine the MACT Floor. EPA has to do this so that the units that set the MACT floor limits can actually comply with those limits. In its industrial boiler information collection request ("ICR"), EPA did not require any testing during start-up and shutdown events. However it is well documented that emissions profiles during these periods are significantly different from those during normal operation. SU/SD periods have highly variable operating conditions and consequently, reference test methods cannot be utilized because the sources do not operate in a steady state as required by the methods. As such, EPA biased the ICR testing by only specifying that tests be conducted at full load operation, and missed the extended start-up periods that electrostatic precipitators ("ESP"), selective catalytic reduction ("SCR"), and some flue gas desulfurization ("FGD") control systems require to achieve optimal performance. Without emissions data during these periods, EPA has no data and no factual basis for concluding that the best performing units can achieve the proposed MACT limits during start-up and shutdown events.
There are inherent problems in setting SU/SDS standards the same as the standards for normal operation, particularly for any standard that is based on an averaging time that is shorter than 30 days or based on a few isolated short-term performance tests. Control devices and mechanisms do not perform at the same level of efficiency during these transitional periods when suitable and stable temperatures or chemical conditions have not been achieved. Certain plant components must be started in a specific sequence in order to ensure that steady state operations can be achieved, and not all pieces of control equipment will be operating at peak efficiency during start-up and shutdown. For example, industrial boilers equipped with SCR, must achieve a minimum flue gas temperature of 535-600 F (depends upon SO_3 concentration) before reagent can be injected and react with the SCR catalyst. Flue gas temperatures must reach 270 F for cold-side ESPs and 600F for hot-side ESPs to effectively control particulate matter ("PM") and HAP associated with PM. A typical hot start-up takes 6-8 hours and a cold start-up may take 8- 24

hours. Industrial boilers equipped with FGDs that use "mag-enhanced lime" can require 24- 36 hours to build proper chemistry conditions for effective control as designed.

Setting standards for SU/SD the same as for normal operation for wood-fired biomass boilers is also problematic. At a recent pollution control user's group conference held in Charlotte NC, Duke Energy and others learned that boiler and pollution control vendors are also concerned with the SU/SD features of the proposed industrial boiler MACT standards. Vendors are unwilling to guarantee emission rates for PM and carbon monoxide ("CO") based on the

proposed ICI boiler MACT standards, and are particularly concerned with the numerical limits for SU/SD. As a consequence, several, untreated wood biomass projects have been postponed or cancelled due to the regulatory and compliance uncertainties of the proposed MACT standards, including the SU/SD provisions. There is no justification or technical basis for setting a numerical SU/SD limit with no data to support the limit. Setting numerical SU/SD limits without data based on an averaging period less than 30 days or based on a single or few isolated performance tests will result in an unattainable standard.

EPA should replace the numerical SU/SD limits with a work practice/operational standard that require owners/operators to maintain and operate the industrial boiler in a manner consistent with good engineering and air pollution control practices as EPA did for the stationary RICE engine MACT rule. Owners/operators could be required to maintain a SU/SD Plan on site that identifies good engineering and pollution control SU/SD practices and procedures that recognize specific boiler and pollution control equipment designs. This approach is justified under the CAA Section 112 (d) and (h), and is the only practical way to address HAP emissions during SU/SD given EPA's lack of any emissions data during these periods. EPA has not established a technical basis to conclude that SU/SD emissions of HAP are the same as during normal operations. The assignment of any SU/SD numerical limit, even based on a 30 day average, is arbitrary and capricious, and infeasible given the lack of test data. The extensive testing that would be required to establish SU/SD numerical limits is not feasible and impractical from a technical or economic perspective. Setting any numerical SU/SD limit would need to be delayed until the necessary testing is completed. Testing would have to be source-specific and based on several tests over an extended period of time to come close to being representative of variations in boiler SU/SD conditions, and specific boiler and pollution control equipment designs. One would expect results of CO, PM, and HAP test results to vary greatly from one test to the next during transition SU/SD periods. FGDs, ESPs, and SCRs do not function or function poorly during SU/SD transitions. Since pollution control equipment is not designed to control during this transition, SU/SD testing would need to be done on essentially an uncontrolled boiler. Mandatory use of control equipment prematurely for the tests could damage or shorten the life of the pollution control equipment (or catalyst) and create unintended operational issues.

Emissions from industrial boilers are different during normal operation and transition periods of SU/SD and it is not feasible to establish numerical emission standards. This situation

is the circumstance in which Congress envisioned a work practice standard for periods of startup, shutdown and malfunction in 112 (h) of the CAA, and they reserved the application of numerical limits for normal operations. Setting MACT standards for normal operation based on suitable data and establishing a work practice/operation standard(s) for SU/SD that recognizes specific boiler and pollution control system designs will result in a MACT standard that applies at all time and is consistent with the recent Court Decision (Sierra Club v. EPA, 551 F. 3d 1019).

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: John C. Hendricks
Commenter Affiliation: American Electric Power
Document Control Number: EPA-HQ-OAR-2002-0058-2703.1
Comment Excerpt Number: 4

Comment: EPA Should Allow for a Startup, Shutdown, and Malfunction Exemption. EPA failed to properly account for periods of startup, shutdowns, and malfunctions in developing the proposed MACT standards. Stack testing during the ICR was done with the units at normal operating loads thereby ensuring that none of the data collected was representative of these periods. Startups and shutdowns occur as a part of normal plant operations; however, the emission rates during these periods are not similar to those during steady-state operation. Unit processes may not operate at peak efficiency until the unit achieves a certain temperature (increase in products of incomplete combustion, control devices not operating properly) or process rate. The increase in actual emission rate would greatly skew the emission rate over the proposed averaging periods due to the scarcity with which AEP's units are operated. A consequence of this is to operate the boilers (normally used for EGU startup) for a greater period of time for emission rate averaging purposes.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: John Hopewell
Commenter Affiliation: American Coatings Association
Document Control Number: EPA-HQ-OAR-2002-0058-2886.1
Comment Excerpt Number: 5

Comment: EPA needs to address specific start-up, shutdown, and malfunction emission standards or work practice standards within the proposed rule.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Holly R. Hart
Commenter Affiliation: United Steelworkers Union
Document Control Number: EPA-HQ-OAR-2002-0058-2964.1
Comment Excerpt Number: 5

Comment: The proposed rule states that startup, shutdown, and malfunction (SSM) events must be subject to the MACT floor. One particular example is coke oven gas (COG) furnaces at steel mills, which must shut down annually 28 days per year; a situation which leads to increased emissions.

USW believes it is essential that SSM data be included in the calculation of the MACT floor for all pollutants and all subcategories. The Union recommends that EPA gather SSM data for all pollutants and subcategories subject to the MACT floor.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Edward Bortz
Commenter Affiliation: SP Newsprint Co LLC
Document Control Number: EPA-HQ-OAR-2002-0058-3128
Comment Excerpt Number: 5

Comment: Provide a Startup Exemption

The proposed rules provide no recognition of the elevated emissions levels associated with the startup of biomass boilers. In order to safely start up a biomass boiler without risk of causing explosion and avoid undue stress to the boiler, it is necessary to heat up the boiler slowly and without the benefit of particulate controls. EPA has recognized that until combustion is stable and the boiler has reached an exhaust temperature of 250F, it is not safe to energize an ESP. This fact has been recognized in prior rules such as the Boiler NSPS. In the proposed rule EPA grants no recognition of the realities of biomass boiler startups, imposing the standards applicable to normal operation to days where startups occur. The only recognition of the anomalous conditions that exist during startup was to state that 24 hours averaging would enable boiler operators to demonstrate compliance notwithstanding startup. This is grossly inaccurate. Startups can routinely take 6 to 8 hours and opacity, as recorded by a continuous opacity monitor, can reach 90 percent. It is known that not all of those readings accurately reflect opacity as considerable moisture is driven off the kindling fuel and the interior surfaces of the boiler, resulting in water vapor that is inaccurately read as opacity. However, there is also significant opacity during startup that is not capable of being reduced as the control equipment cannot be energized until the moisture is driven off and the interior surfaces adequately warmed up. Rushing this process can result in damage to control equipment and explosion concerns. As a result, notwithstanding good operation, it is mathematically impossible to average the startup opacity conditions with the opacity once normal operations have commenced to comply with a 10 percent opacity standard applicable to those biomass boilers employing ESPs or scrubbers (the vast majority of the controlled boilers in this subcategory).

We strongly encourage EPA to develop an exception to compliance with the work practice standards. Other recently promulgated NESHAPs have recognized that it is impossible to demonstrate compliance with emission standards during startup conditions and have allowed sources a reasonable period where they do not need to demonstrate compliance with the limits. For example, the Subpart ZZZZ NESHAP allows natural gas and diesel fired engines a 30 minute startup period during which the standards do not apply. If this can be allowed for fossil fuel fired units such as reciprocating internal combustion engines, a similar approach should be recognized for biomass boilers. Therefore, we recommend that EPA revise the rules to allow an 8 hour startup period during which the limits do not apply. Because this time may not be adequate for startup of some larger boilers without any supplementary fuel capability, we also suggest that EPA clarify that sources can apply to EPA for a longer startup time period.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Marvis A. Lewallen
Commenter Affiliation: Clearwater Paper
Document Control Number: EPA-HQ-OAR-2002-0058-2862
Comment Excerpt Number: 5

Comment: The proposed rules provide no recognition of the elevated emissions levels associated with the startup of biomass boilers. In order to safely start up a biomass boiler without risk of causing explosion and avoid undue stress to the boiler, it is necessary to heat up the boiler slowly and without the benefit of particulate controls. EPA has recognized that until combustion is stable and the boiler has reached an exhaust temperature of 250F, it is not safe to energize an ESP. This fact has been recognized in prior rules such as the Boiler NSPS. In the proposed rule EPA grants no recognition of the realities of biomass boiler startups, imposing the standards applicable to normal operation to days where startups occur. The only recognition of the anomalous conditions that exist during startup was to state that 24 hours averaging would enable boiler operators to demonstrate compliance notwithstanding startup. This is grossly inaccurate. Startup on one of our hog fuel boilers take over 10 hours before the ESP can safely be energized. It is understood that not all of the opacity readings during this period accurately reflect opacity as considerable moisture is driven off the kindling fuel and the interior surfaces of the boiler, resulting in water vapor that is inaccurately read as opacity. However, there is also significant opacity during startup that is not capable of being reduced as the control equipment cannot be energized until the moisture is driven off and the interior surfaces adequately warmed up. Rushing this process can result in damage to control equipment and explosion concerns. As a result, notwithstanding good operation, it is mathematically impossible to average the startup opacity conditions with the opacity once normal operations have commenced to comply with a 10 percent opacity standard applicable to those biomass boilers employing ESPs or scrubbers (the vast majority of the controlled boilers in this subcategory).

We strongly encourage EPA to develop an exception to compliance with the work practice standards. Other recently promulgated NESHAPs have recognized that it is impossible to demonstrate compliance with emission standards during startup conditions and have allowed sources a reasonable period where they do not need to demonstrate compliance with the limits.

For example, the Subpart ZZZZ NESHAP allows natural gas and diesel fired engines a 30 minute startup period during which the standards do not apply. If this can be allowed for fossil fuel fired units such as reciprocating internal combustion engines, a similar approach should be recognized for biomass boilers. Therefore, we recommend that EPA revise the rules to allow an 8 hour startup period during which the limits do not apply. Because this time may not be adequate for startup of some larger boilers without any supplementary fuel capability, we also suggest that EPA clarify that sources can apply to EPA for a longer startup time period.

Response: See the preamble changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Thomas Bakk
Commenter Affiliation: State of Minnesota Senate
Document Control Number: EPA-HQ-OAR-2002-0058-2950
Comment Excerpt Number: 6

Comment: Startup, Shutdown, Malfunction: The proposed standards do not adequately account for periods of startup, shutdown or malfunction because the EPA uses short-term performance test results to set emission limits, not the results of long-term Continuous Emission Monitoring. EPA must recognize that boilers do not run at a "steady state" condition; therefore the proposed limits cannot be met while boilers are starting up and shutting down.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: J. Michael Geers
Commenter Affiliation: Duke Energy
Document Control Number: EPA-HQ-OAR-2002-0058-2765.1
Comment Excerpt Number: 6

Comment: Vendors question whether the CO standards are achievable during start up/shut down after CO and PM MACT controls are installed. Boiler vendors are unwilling to guarantee emission rates based

on the proposed ICI boiler MACT standards for PM and CO for new, reconstructed, and modified industrial boilers designed for wood biomass, particularly where the SU/SD standard is based on a daily averaging time or where performance testing includes SU/SD. Owners/operators of ICI boiler sources must have alternatives that provide a suitable chance for compliance during transitional SU/SD periods when their units are equipped with MACT controls.

Response: See the preamble for response to how EPA adjusted CO emission limits and compliance mechanisms, and changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Leslie Sue Ritts
Commenter Affiliation: National Environmental Development Association's Clean Air Project NEDA/CAP
Document Control Number: EPA-HQ-OAR-2002-0058-2794.1
Comment Excerpt Number: 9

Comment: It is common knowledge that high CO levels result from incomplete combustion; information which EPA and the courts can take notice. Moreover, EPA's own data on emissions during startups and shutdowns demonstrates that carbon monoxide levels are up to twenty times greater during such periods. Oxygen levels are higher, resulting in the corrected pollutant concentrations being much higher when fuel values are low, as during periods of start-up and shutdown. If EPA had examined these data in some detail, it would have recognized two important aspects of the startup and shutdown periods. First, during startup periods, the oxygen content of the flue gas is generally very high, resulting in high calculated concentrations of pollutants, when they are corrected to 3 or 7 percent oxygen. Second, during shutdown periods many types of boilers continue to emit pollutants for some time while the fuel feed rate has gone to zero. Thus, during those periods the pollutant emission rates when measured in terms of the heat input rate would contain a zero in the denominator and would equal infinity. Combining emissions during shutdown periods with all operating periods would mean an emission limit of infinity. Based on this ridiculous outcome, we recommend that EPA exclude periods of startup and shutdown from its numerical standards and replace them with work practice standards aimed at minimizing pollutant emissions.

Response: See the preamble for response to how EPA adjusted CO emission limits and compliance mechanisms, and changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Leslie Sue Ritts
Commenter Affiliation: National Environmental Development Association's Clean Air Project NEDA/CAP
Document Control Number: EPA-HQ-OAR-2002-0058-2794.1
Comment Excerpt Number: 10

Comment: Sierra Club v. EPA does not require EPA to establish standards that included SSM events.

EPA also asserts that "Consistent with Sierra Club v. EPA, EPA has established standards in this rule that apply at all times." 75 Fed. Reg. 32012 (emphasis added). But the court's 2008 decision does not require SSM events be part of a single standard that applies at all times. In Sierra Club

v. EPA, 551 F.3d 1019 (D.C. Cir. 2008), cert. denied, 2010 U.S. LEXIS 2265(2010), which vacated the "automatic" exemption in 40 C.F.R. § 63.6(f)(1) and (h)(1) for SSM periods, the D.C. Circuit ruled simply that sources cannot be exempt from complying with MACT standards. However, the court also noted that Congress recognized in some instances that it may not be feasible to prescribe or enforce an emission standard under section 112, and so section 112(h) "work practices" or "operational" standards may be available. Id. at 1028. Moreover, the same court also has recognized that standards based on what sources achieve must account for the limitations inherent in the technology used to reduce emissions. For example, in a case reviewing NSPS under section 111 of the CAA, Portland Cement Ass'n v. Ruckelshaus, 486 F.2d 375, 398 (D.C. Cir. 1973), the court acknowledged that "'startup? and „upset? conditions due to plant or emission device malfunction, is an inescapable aspect of industrial life and that allowance must be made for such factors in the standards that are promulgated." Id.
at 399. In sum, these opinions support separate provisions in a standard that address control of emissions during different operating modes, including start-ups and shutdowns.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Leslie Sue Ritts
Commenter Affiliation: National Environmental Development Association's Clean Air Project NEDA/CAP
Document Control Number: EPA-HQ-OAR-2002-0058-2794.1
Comment Excerpt Number: 11

Comment: Malfunctions, particularly, should be treated as a "distinct operating mode" and accordingly require a separate standards.

With regard to malfunctions, EPA argues in the preamble to the Proposed Boiler MACT that these periods should not be viewed as a "distinct operating mode," and thus, emissions from these periods do not need to be factored into developing the MACT floor levels. 75 Fed. Reg. 32013. Moreover, EPA states that even if malfunctions were to be considered a distinct operating mode, it would be "impracticable to take malfunctions into account in setting CAA section 112(d) standards for major source boilers and process heaters" given that these episodes are by definition sudden and unexpected events which vary in degree, frequency, and duration. Id.

Considering that EPA's proposed MACT standards are supposed to apply at all times, the implication is that periods of malfunction also are covered by the same MACT standards that also apply during normal operations. This directly conflicts with the statutory requirement that the MACT standard be "achievable." EPA has failed to recognize that it is likely that even best performers will experience malfunctions and that is unreasonable. It is possible for pollution control equipment to fail in various ways. Electrostatic fields trip, power failures occur, fabric filters fail, and scrubber pumps fail -- even at best performers and despite the best efforts of companies to prevent and minimize such events. Industry can and does work to minimize such periods and the resulting emissions, but they do occur. Further, manufacturers of such equipment routinely make emission guarantees for normal operations and although they sometimes oversize equipment to account for some of the variability described above, it is very doubtful that vendors would provide sufficient numerical guarantees for equipment under all start-up, shutdown and malfunction situations.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: John W. Fainter, Jr.
Commenter Affiliation: Association of Electric Companies of Texas
Document Control Number: EPA-HQ-OAR-2002-0058-2790.1
Comment Excerpt Number: 11

Comment: Inclusion of an affirmative defense for start-up, shutdown, and malfunction
AECT opposes EPA's proposal to omit from the IB MACT proposed rule an affirmative defense for excess emissions of HAP during periods of start-up, shutdown, and malfunction ("SSM"). EPA's proposed rule unnecessarily disregards the special circumstance of excess emissions of HAP during SSM and EPA has seemingly broadened the D.C. Circuit's holding, by not only providing no SSM exclusions, but also by offering no alternative provisions addressing excess emissions during periods of SSM.

AECT urges EPA to include an affirmative defense during periods of SSM in the IB MACT proposed rule. Specifically, EPA should provide that, while periods of excess emissions during startup and shutdown would be considered violations, an owner could raise an affirmative defense. Nothing in the D.C. Circuit's opinion precludes EPA from including an affirmative defense for excess emissions during periods of SSM. In fact, doing so would be consistent with EPA's approval of similar State Implementation Plan (SIP) provisions and EPA's previous guidance on SSM.

Similar affirmative defense provisions have recently be approved into several states' SIPs. For example, both the Colorado SIP and the New Mexico SIP contain an affirmative defense for excess emissions during periods of startup and shutdown. It is important to note that when EPA approved the affirmative defense provisions, it stated that that affirmative defense provisions are "consistent with the provisions for startup and shutdown we suggested in our September 20, 1999 memorandum." (71 Fed. Reg. at 8959 74 Fed. Reg. at 46912).

In fact, the IB 1CR did not require any testing during SSM . Operations during boiler start-ups are different than normal plant operations. For many AECT members' it is simply not feasible from a technical or safety perspective to operate certain emissions control equipment during all parts of a startup or shutdown, or at least to operate such equipment "consistently effective" during all parts of a startup or shutdown. Without emissions data during these periods, EPA has absolutely no factual basis for concluding that the best performing units can achieve the proposed IVIACT limits during SSM events.

Including an affirmative defense is consistent with EPA's policy regarding exclusions during periods of SSM. Unlike an exclusion, an affirmative defense does not excuse a source from continuous compliance, The affirmative defense merely relieves the source of any penalty imposed as a result of non-compliance during a period of SS1V.1. It does not relieve the source of the requirement to comply With the applicable standard.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Cathy S. Woollums
Commenter Affiliation: MidAmerican Energy Holdings Company
Document Control Number: EPA-HQ-OAR-2002-0058-2786.1
Comment Excerpt Number: 11

Comment: The Proposed Limits Cannot Be Achieved During Periods of Start-up, Shut-down and Malfunction. While MidAmerican is mindful of the need to avoid complete exemptions during periods of start-up, shut-down and malfunction, alternative emission limits should be considered during these periods to account for such events. Clearly, the start-up of a boiler is an event that is anticipated and cannot be avoided; in fact, in order to comply with all the provisions of the proposed rule, many facilities will have to take outages to both install controls or to perform the requisite assessments that the proposed rule requires. As a consequence, facilities should not be forced into a situation that upon start-up, they are out of compliance with the emission standards, particularly for CO. Cold starts, when equipment temperature is low, will inevitably result in higher CO emissions for short periods of time. MidAmerican does not believe that EPA has appropriately accounted for higher levels of emissions during such periods. EPA should establish an alternative emission limit for startup periods based on boiler types and loads, as well as to account for variability during shutdown periods.

Response: See the preamble for response to how EPA adjusted CO emission limits and compliance mechanisms, and changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Leslie Sue Ritts
Commenter Affiliation: National Environmental Development Association's Clean Air Project NEDA/CAP
Document Control Number: EPA-HQ-OAR-2002-0058-2794.1
Comment Excerpt Number: 12

Comment: Given that the floor data does not consider malfunctions and that the statute requires that the MACT standard be "achievable," EPA should set work practice requirements to address periods of malfunctions as well. As noted above, section 112(h) allows EPA to set work practice standards for situations where "it is not feasible in the judgment of the Administrator to prescribe or enforce an emission standard . . . .” Similar to startups and shutdowns, malfunctions fit with the situations described in the definition of “not feasible to prescribe or enforce an emission standard” as any situation where “the application of measurement methodology to a particular class of sources is not practicable due to technological and economic limitations.” Emission testing for malfunctions would be near impossible to conduct given the sporadic and unpredictable nature of the events. As noted earlier, EPA acknowledges in the preamble to the Proposed Boiler Rule that it is “impracticable” to take periods of malfunctions into account when setting emissions standards given the “myriad different types of malfunctions that can occur across all sources in the category” and that “malfunctions can vary in frequency, degree, and duration, further complicating” the standard setting process. 75 Fed. Reg. 32013. Section 112(h) work practice standards, therefore, are well-suited to address malfunction periods and the complexities and challenges surrounding collecting data and establishing numerical standards for those events.

For these reasons, NEDA/CAP believes that it is appropriate for EPA to revisit this issue. NEDA/CAP suggests that EPA propose work practice standards that would allow sources a certain time period for start-up, shutdown and malfunction events and, as long as certain procedures are followed, then compliance would be met. Those work practice standards should require the development and implementation of an emissions minimization plan that will result in (a) minimizing emissions during such events that would exceed otherwise applicable emission limitations, and (b) for malfunctions that will cause the unit to exceed otherwise applicable emission limitations, promptly identifying and implementing measures to remedy the malfunction. While there may be some instances where standard work practices can be identified for a type of source, NEDA/CAP cautions that overly prescriptive and non-facility-specific requirements can actually be counterproductive, restricting the operators’ flexibility in a way that hampers their ability to troubleshoot or respond to an event, or that compromises safety. The plan itself should not be incorporated into the Title V permit. The plan should be an evolving document, and it would be very cumbersome to have to seek a modification of the Title V permit every time the plan changed. If the details of the emissions minimization plan had to be made part of the permit, facilities would tend to make the plans less specific and therefore probably less useful. For the same reason, these plans should be maintained at the facility rather than being required to be submitted to the permitting authority with the Title V application or otherwise.

Alternatively, EPA could establish a threshold of exceedances as either a number or percentage of operating times that could occur during a quarterly or six month period before a violation occurs. This methodology is consistent with other MACT standards such as 40 CFR 63 Subparts S and MM.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Chris M. Hobson
Commenter Affiliation: Southern Company
Document Control Number: EPA-HQ-OAR-2002-0058-2741.1

Comment Excerpt Number: 13

Comment: The IB ICR did not require any testing during start-up, shutdown and malfunction events. Without emissions data during these periods, EPA has absolutely no factual basis for concluding that the best performing units can achieve the proposed MACT limits during start-up, shutdown and malfunction (SSM) events. EPA must obtain emission information during SSM events in order to set standards during SSM. Alternatively, work practice standards are far more appropriate since measuring emissions during SSM is often not possible and generally not feasible.

Although Southern Company does not have emission test data during periods of SSM for our oil, natural gas, or biomass-fired boilers, we do have continuous mercury emissions information from some of our coal-fired utility boilers. We have learned at our coal plants that periods of SSM may impact emission control performance and affect our ability to meet emission standards during SSM events.

Operationally, SSM time is minimized since these events lead to increased wear and tear on plant components. Nevertheless, SSM events are unavoidable and make up a small part of the plant's normal operating cycle.

Periods of startup must account for the length of the boiler startup as well as the system startup (e.g., startup of the emission controls). Startup of emission controls to normal operating conditions requires as much and generally more time than the startup of the boiler itself. Although longer averaging times may account for this startup (assuming reasonable emission limits), it will likely be impossible to meet 24-hour block averages, considering startups can last > 36 hours, and be very difficult to meet 30-day rolling averages, especially if there is more than one startup or malfunction in any 30 day period. Unless EPA gathers data for emission during SSM events and considers acceptable emission limits with averaging times long enough to account for normal plant startups and malfunctions (e.g., annual averages), EPA should not set emission standards during these events. Work practices standards are far more appropriate during periods of start-up, shutdown and malfunction.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Chris M. Hobson
Commenter Affiliation: Southern Company
Document Control Number: EPA-HQ-OAR-2002-0058-2741.1
Comment Excerpt Number: 14

Comment: Plant startups fall into two categories – plant startup following a forced (or unplanned) outage (hot startup) and plant startup following a planned outage (cold start). Both outage types occur at any facility and are required for maintenance purposes. These types of plant startups mainly differ in their duration and frequency. Hot plant startups following a forced outage are more common and typically shorter in duration. For example, a coal plant may startup following a forced outage >10 times per year. Long extended maintenance outages are planned in advance and last for several weeks, but they occur annually or even farther apart.

All plant startups are composed of multiple equipment startups, ranging from the startup of small equipment (e.g. thermocouples) to large reactors -- e.g. boiler, SCR, wet flue gas desulfurization (FGD or scrubber) system. Each of these systems necessarily has a different time constant associated with its startup. During this period, equipment may operate far outside of its design conditions. If the equipment is part of HAPs control, this type of operation can lead to high emission events during plant startup. See submittal for data from two large coal-fired utility plants that show: 1) the duration of plant startups and 2) how the startup cycle affects mercury emissions.

Figure 1 shows the cold startup of a coal-fired plant equipped with oil igniters. This startup followed a planned outage. During oil-firing, the SCR is fully bypassed in order to prevent catalyst poisoning and potential fire hazards. Full bypass continues until coal-firing begins and stable boiler operation is achieved. Operational tie-in of the SCR is initiated by a gradual opening of the SCR inlet dampers. This partial bypass period is required to minimize thermal stress, ammonium bisulfate formation, and acid corrosion. Mercury emissions are elevated until all of the flue gas passes through the SCR. Like other high emission events, these startup periods could represent a significant portion of a plant's emissions during a given averaging period.

Figure 2 of the submittal shows an example of an unplanned plant shutdown and hot plant startup following a short forced outage. The shutdown of the plant in this outage did not result in any unusual mercury emissions. However, the startup cycle did impact emissions significantly. The boiler while being started reaches full rated capacity in 10 hours. Full and partial SCR bypass lasts only 8 hours. During this period, mercury emissions are elevated. However, note that mercury emissions remain above their pre-outage average value of ~1 lb/TBtu even after the SCR bypass has ended (see both Figures 1 and 2). This phenomenon is not well understood, but may be due to desorption of mercury from the hot catalyst or mercury re-emission. Thus, in terms of Hg emissions for a plant equipped with an SCR and wet FGD system, the startup period may last >36 hours.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Chris M. Hobson
Commenter Affiliation: Southern Company
Document Control Number: EPA-HQ-OAR-2002-0058-2741.1
Comment Excerpt Number: 15

Comment: Malfunctions can be of two different types – malfunction of the emissions control equipment controlling HAPs emissions, or malfunction of the boiler equipment unrelated to the emissions control systems. Clearly, malfunctions of the emissions control systems should warrant corrective action, but system malfunctions can result in increased emissions unrelated to the operation of the emissions controls. For example, if a component malfunction requires the operation of the boiler be less than the minimum temperature for a SCR, then the SCR would have to be placed in bypass while the flue gas temperature is too low, and this action could increase mercury emissions in the examples above.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: David Bonistall
Commenter Affiliation: NewPage Corp
Document Control Number: EPA-HQ-OAR-2002-0058-2920.1
Comment Excerpt Number: 18

Comment: EPA has made a similar mistake with regard to its proposal to not set a separate standard for periods of startup, shutdown, and malfunction. On the one hand, EPA asserts that "[t]he standards we are proposing are daily or monthly averages ... [t]hus, we are not establishing separate emission standards for these periods because startup and shutdown are part of their routine operations and, therefore, are already addressed by the standards." On the other hand, EPA uses short-term performance test results to set the standards rather than the results of long-term CEMS monitoring. As a result, the emissions data on which the standards are based do not, in fact, reflect or adequately accommodate emissions from periods of startup, shutdown, or malfunction. To assure that startup, shutdown and malfunction are appropriately accommodated, EPA must either assure that the data on which the standard is based include representative data from such periods or, alternatively, set a separate work practice standard to properly accommodate startup, shutdown and malfunction.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: John C. deRuyter
Commenter Affiliation: DuPont
Document Control Number: EPA-HQ-OAR-2002-0058-2793.1
Comment Excerpt Number: 19

Comment: SSM

EPA has proposed that their averaging time basis for compliance with the emissions limits would be adequate to cover startup and shutdown periods and malfunctions are simply not addressed in that they should not occur. DuPont believes this approach is unworkable and fails to recognize the realities of operating the many types of boilers and process heaters. As a base issue, EPA has not utilized long term emissions data such as CO CEMS data to adjust emissions test data to be representative of actual operating data over time. Additionally, while a couple of the 30 day CEMS test units included startups and shutdowns within the period, that was not done for all units. So there is no allowance for emissions during SS periods in the proposed limits. It is not feasible to conduct emissions testing during SSM periods due to the variable nature of those conditions. It is not feasible to conduct emissions testing during malfunctions since by definition there are operational problems that could indeed be safety issues during those periods. Therefore, trying to incorporate SSM periods into an emission limit that must be met at all times is fraught with problems. We are concerned that if such limits were set, operators could be placed in an untenable position of trying to operate equipment and not exceed emissions limits, and be tempted to take shortcuts that could place equipment and personnel at risk relative to equipment integrity and safety.

Therefore, we urge EPA to utilize its discretion to allow facilities to establish site and unit-specific startup and shutdown plans as a work practice approach during SS periods so that appropriate practices are followed with minimization of emissions during those periods to the extent practical. Malfunctions should also be managed similarly with a malfunction plan, so that operators are knowledgeable and trained to recognize potential malfunctions and to take appropriate actions which allow for safety as of utmost importance with protection of equipment integrity.

Response: See the preamble for response to how EPA adjusted CO emission limits and compliance mechanisms, and changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Pamela F. Faggert
Commenter Affiliation: Dominion
Document Control Number: EPA-HQ-OAR-2002-0058-2908.1
Comment Excerpt Number: 19

Comment: The MACT floor analysis does not account for effects of startup, shutdown, or malfunction (SSM) on combustion-related HAPs emissions (CO and dioxin/furans) and PM emissions for new or existing units. This is critical for units that are required to demonstrate continuous compliance with the CO limit using a CO CEMS and with the PM limits using PM CEMS, since 40 CFR Part 63 no longer includes exemptions for SSM periods.
EPA does not have sufficient data (neither reference method nor CEMS data) for those units in the MACT floor to address variability in PM emissions due to startup/shutdown. It is also questionable whether representative measurements could even be obtained during boiler startup/shutdown due to the dynamic flue gas conditions and technical limitations associated with the measurement technology. For these reasons, EPA must either assure that the data on which the standard is based include representative data from such periods or, alternatively, set a separate work practice standard to properly accommodate startup, shutdown, and malfunction.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: J. Michael Geers
Commenter Affiliation: Duke Energy
Document Control Number: EPA-HQ-OAR-2002-0058-2765.1
Comment Excerpt Number: 21

Comment: EPA Has No Basis to Expect That Operating Parameter Limits Established During Performance Tests Will Be Achievable During Startup, Shutdown, and Malfunction
Duke Energy is 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. When EPA finalized its rule in 2004 with enforceable operating parameters, it did so with a rule that also made clear that those limits did not apply during periods of "startup, shutdown, and malfunction." 40 C.F.R. 63.7505(a), 69 Fed. Reg. at 55,254. EPA's current proposal contains no such exception, but instead would allow enforcement of deviations from operating parameters during periods of startup and shutdown, when controls would not be expected to be operating at the same levels as during performance tests, and due solely to equipment malfunctions. In the preamble, EPA discusses its approach to these events. 75 Fed. Reg. 32013. Regarding startup and shutdown, EPA asserts that it has taken these periods into account by using GEMS data from best performing units that include periods of startup and shutdown, and by proposing use of "daily or monthly averages." Regarding malfunctions, EPA asserts that it would use a variety of information to determine an appropriate response to exceedances caused by equipment malfunction.
EPA's preamble assertions regarding startup and shutdown are inapplicable to control device operating parameter limits, which are based on 12-hour averages (not daily or monthly averages) established during performance test (not based on GEMS data that include startup and shutdown). Even a daily block average, as proposed for opacity, does not provide sufficient protection if the unit does not startup or shutdown at exactly midnight, since there might not be sufficient data under normal operating conditions to compensate for the startup or shutdown period. In short, EPA has made absolutely no allowance in its rules for periods of startup and shutdown yet it has specific evidence that these periods are distinctively different. To the contrary, EPA has proposed to require sources to establish control device operating parameters levels that are dependent upon load during periods of "maximum normal operating load," and then maintain those levels during periods other than maximum normal operating load, including startup and shutdown. EPA's proposal is patently unreasonable. EPA must address these periods in some other manner, for example by establishing simple work practice standards in lieu of operating parameters.

EPA's promise to address periods of equipment malfunction by considering other information before enforcing exceedances of operating limits provide little comfort, especially given the risk of citizen suits. Although Duke Energy appreciates EPA's proposal to make clear that "deviations" of operating limits are not necessarily violations, nothing in EPA's proposal would prevent EPA, a state, or a plaintiff in a citizen suit from simply determining in their "discretion" that any particular exceedance constitutes a violation. Proposed § 63.7575. MACT standards are technology-based standards and must recognize that even the best performing technology occasionally fails.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Chris M. Hobson
Commenter Affiliation: Southern Company
Document Control Number: EPA-HQ-OAR-2002-0058-2741.1
Comment Excerpt Number: 32

Comment: The MACT floor analysis does not account for effects of startup, shutdown, or malfunction (SSM) on combustion-related HAPs emissions (CO and D/F) for new or existing units. This is critical for units that are required to demonstrate continuous compliance with the CO limit using a CO CEMS since Part 63 no longer includes exemptions for SSM periods.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Pamela F. Faggert
Commenter Affiliation: Dominion
Document Control Number: EPA-HQ-OAR-2002-0058-2908.1
Comment Excerpt Number: 32

Comment: Operating Parameter Limits Established During Performance Tests Will Not Be Achievable During Startup, Shutdown and Malfunction
Proposed Section 63.7540 requires continuous compliance with non-monitored limits, such as HCL and Hg, by establishing operating parameter (such as scrubber pH, slurry flow, pressure drop, liquid flow-rated and sorbent injection rate for scrubbers) maximums and minimums that would be established during initial compliance tests (required by 63.7530) to meet the HCL and Hg limits. Operation outside of these limits will be considered a deviation from the operating limits. When EPA finalized its rule in 2004 with enforceable operating parameters, it made clear that those limits did not apply during periods of "startup, shutdown, and malfunction." The current proposal contains no such exception, but instead would allow enforcement of deviations from operating parameters during periods of startup and shutdown, when controls would not be expected to be operating at the same levels as during performance tests, and due solely to equipment malfunctions. In the preamble, EPA asserts that it has taken these periods into account by using CEMS data from best performing units that include periods of startup and shutdown, and by proposing use of "daily or monthly averages." Regarding malfunctions, EPA asserts that it would use a variety of information to determine an appropriate response to exceedances caused by equipment malfunction". These assertions regarding startup and shutdown are inapplicable to control device operating parameter limits, which are based on 12-hour averages (not daily or

monthly averages) established during performance test (not based on CEMS data that include startup and shutdown). Even a daily block average, as proposed for opacity, does not provide sufficient protection if the unit does not startup or shutdown at exactly midnight, since there might not be sufficient data under normal operating conditions to compensate for the startup or shutdown period. In short, no allowance for periods of startup and shutdown has been provided in the proposed rule. To the contrary, sources are required to establish control device operating parameters levels that are dependent upon load during periods of "maximum normal operating load," and then maintain those levels during periods other than maximum normal operating load, including startup and shutdown. These periods must be addressed by allowing sources to identify alternative parameters or by establishing simple work practice standards for these periods.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Chris M. Hobson
Commenter Affiliation: Southern Company
Document Control Number: EPA-HQ-OAR-2002-0058-2741.1
Comment Excerpt Number: 34

Comment: RMB recommends an alternative approach for addressing load-related variability in CO and D/F emissions based on a comparison of CO levels during periods of startup/shutdown to normal, steady-state operation for several different units within the same fuel/boiler-type subcategory.

This would require a review of the unit operating data to determine each startup/shutdown period. A variability factor (Ksusd) could be established for each unit by calculating the average CO emissions during startup/shutdown (Csusd) divided by the average CO emissions during normal, steady-state operation (Css). This could be conducted for each startup/shutdown event in the observation period and averaged for the unit. An overall variability factor could then be calculated based on an average Ksusd for all units in the boiler-type subcategory. The load-related variability factor would be applied in addition to the 99% UPL variability analysis, which characterizes inter-unit steady-state operating variability and measurement-related variability. RMB notes that this alternative approach does not address malfunction-related variability since it would be impossible to establish a representative malfunction event. However, the use of a 30-day averaging period may help to offset this deficiency.

Unfortunately, EPA does not have sufficient CEMS data in the ICR database for those units in the MACT floor pool to address load-related variability using the alternative approach. EPA will need to obtain additional data in order to conduct this analysis. In obtaining this data, RMB recommends that EPA include periods of startup/shutdown (particularly cold-start) that are representative of each boiler type.

Response: See the preamble for response to how EPA adjusted CO emission limits and compliance mechanisms, and changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Chris M. Hobson
Commenter Affiliation: Southern Company
Document Control Number: EPA-HQ-OAR-2002-0058-2741.1
Comment Excerpt Number: 35

Comment: The MACT floor analysis does not account for the effects of SSM on PM emissions for new or existing units. This is critical for those units that are required to demonstrate continuous compliance with the PM limit using a PM CEMS since Part 63 no longer includes exemptions for SSM periods. Furthermore, the relatively short proposed averaging period (24 hour block) would make compliance with these limits especially difficult, if not impossible, for most units.

EPA does not have sufficient data (neither reference method nor CEMS data) for those units in the MACT floor to address variability in PM emissions due to startup/shutdown. Moreover, RMB has concerns over whether representative measurements could even be obtained during boiler startup/shutdown due to the dynamic flue gas conditions and technical limitations associated with the measurement technology. For instance, changes in particle size distribution or unburned levels during startup affect PM CEMS measurement accuracy, particularly those using optically-based technologies.

Because the variability effects can not be adequately addressed, RMB recommends that EPA remove the requirement for the installation and use of PM CEMS as the continuous compliance determination method for coal and biomass sources with heat input ratings greater than 250 mmBtu/hr. Alternatively, sources could demonstrate a reasonable assurance of compliance based on opacity or parametric monitoring as EPA has already proposed for those units with heat input ratings < 250 mmBtu/hr. EPA could allow the installation and operation of a PM CEMS as an option for all sources, which is consistent with approach taken in the recent revisions to NSPS Subpart Da. However, in this case, RMB would recommend increasing the compliance averaging time (i.e. 30-day rolling average) in order to mitigate some of the effects of startup/shutdown.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Russ A. Wozniak
Commenter Affiliation: Dow Chemical Company
Document Control Number: EPA-HQ-OAR-2002-0058-2632.1
Comment Excerpt Number: 63

Comment: EPA's final rules should realize that the owner/operator will not be able to meet some parameter limits during time of start-up or shutdown. Per other comments, the owner/operator should be provided with a reasonable amount of time to start-up or shutdown facilities without parameter monitoring values counting against compliance with any sort of parameter limit.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Russ A. Wozniak
Commenter Affiliation: Dow Chemical Company
Document Control Number: EPA-HQ-OAR-2002-0058-2632.1
Comment Excerpt Number: 73

Comment: EPA Needs to Further Develop Regulatory Requirements for Times of Start-Up, Shutdown, and Malfunction. EPA's proposed rule requires that emission limits apply at all times, including times of Start-up, Shutdown, and Malfunction (SSM). EPA needs to further develop the requirements for boilers and heaters during times of SSM. CO and oxygen levels will be significantly higher during an initial period of start-up when combusting gaseous fuels. This is due to the boiler operating during this transition time between zero load and the desired operating load. A gas fired boiler could have CO emissions 5 to 25 times above the proposed 1 ppmv limit for over 7 hours during this start-up mode. The following graph shows how CO concentrations change during times of start-up at a boiler that combusts as a mixture of natural gas and Gas2 fuels. [See submittal for figure, "Boiler 1 Startup."] Also, oxygen concentrations vary during times of start-up, making the CO correction to 3% oxygen a very significant one. For example, during times of start-up, the oxygen concentration may be ~ 15%, so the correction to 3% oxygen would be 17.9/5.9 or approximately a factor of 3. Even a small number of hours with high CO concentrations could create a situation where the source could not meet a low CO concentration level over a 30 day averaging period.

Response: See the preamble for response to how EPA adjusted CO emission limits and compliance mechanisms, and changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Russ A. Wozniak
Commenter Affiliation: Dow Chemical Company
Document Control Number: EPA-HQ-OAR-2002-0058-2632.1
Comment Excerpt Number: 74

Comment: Boilers and Process Heaters that combust other gaseous fuels - If these sources remain subject to a numerical emission standard vs. a work practice standard - These sources should be subject only to a work practice standard during SSM periods that requires the boiler or heater and any air pollution equipment to achieve steady state operating conditions within 24 hours from the commencement of start-up. In addition, since most of Dow's boilers/heaters do not start-up more than 1 time per quarter, EPA could limit the use of the work practice standard for 96 hours per year. Thus, similar to the recently promulgated Engine RICE MACT rule amendments, the boiler/heater would not be subject to a numerical emission standard for the hours that it takes to ramp up steam production and pressures. Adopting this approach would continue to minimize any HAP emissions from theses sources without jeopardizing the ability of the source to meet a CO emission level over a 30 day period.

Boilers that Combust Solid Fuels - Solid Fuel Boilers should be subject to the same type of work practice requirements as described above in comment #1 for gas fueled sources. This type of work practice would allow for the time required to start-up these types of boilers and to bring emission control equipment on-line such as an Electrostatic Precipitator (ESP).

Dow proposes the following regulatory text for EPA's consideration in section 63.7505(a):

Emission limits apply at all times, except during times of SSM where the SSM work practice requirements apply instead.

Response: See the preamble for response to how EPA adjusted CO emission limits and compliance mechanisms, and changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Russ A. Wozniak
Commenter Affiliation: Dow Chemical Company
Document Control Number: EPA-HQ-OAR-2002-0058-2632.1
Comment Excerpt Number: 76

Comment: Item #2 from Table 9 Should be Deleted since the SSM Plans are not required by this proposed rule. EPA proposes in Table 9 of the proposed rule that the owner/operator should make an immediate startup, shutdown, and malfunction report if one has a startup, shutdown, or malfunction during the reporting period that is not consistent with the startup, shutdown, and malfunction plan, and if the source exceeds any applicable emission limitation in the relevant emission standard.

EPA should remove this requirement prior to publishing the final rule. In Table 10 of the proposed rule, EPA clearly notes that the requirements of 40 CFR 63.6(e)(3) (i.e., requirement to prepare a written SSM plan) do not apply.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Ken Wiegand
Commenter Affiliation: Denison University
Document Control Number: EPA-HQ-OAR-2002-0058-2834.1
Comment Excerpt Number: 1

Comment: The manufacturers of existing fabric filter control equipment require that the control equipment be bypassed until it is up to operational temperature. Failure to follow the manufacturers operational procedure, results in premature failure of the bags (fabric filters) in the control equipment. The estimated cost to replace the bags (fabric filters) in Denison University's control equipment is $50,000.00. As a result, the emissions data on which the standards are based do not, in fact, reflect or adequately accommodate emissions from periods of startup, shutdown, or malfunction.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Michael Hutcheson
Commenter Affiliation: Ameren Services
Document Control Number: EPA-HQ-OAR-2002-0058-2803.1
Comment Excerpt Number: 1

Comment: US EPA requests comment on whether additional provisions should be added to regulatory text in light of the absence of an SSM exemption. Ameren believes that US EPA errs by not including an exemption for Startups, Shutdowns and other transient events such as malfunctions which are inherently uncontrolled or difficult to control. US EPA has not even attempted to show that given the complex array of add-on controls and fuel mixes required for compliance with this standard sources will be able to achieve the vary stringent limitations during these times.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: David M. Kiser
Commenter Affiliation: International Paper Company
Document Control Number: EPA-HQ-OAR-2002-0058-2777.1
Comment Excerpt Number: 2

Comment: Much, if not all, of the emission data used to establish the proposed limits are from performance tests conducted in response to EPA's Section 114 directive. Boilers were required to be tested "at loads that represents typical conditions" and "under normal operating conditions" which in the historical context of performing stack tests has meant relatively smooth operating conditions, exclusive of dramatic operating swings which may occur due to a variety of real-world conditions that can and do happen even in those best-performing units. Such ideal conditions are achievable only when all operations are functioning properly and smoothly which does not occur all the time. A problem is that these relatively smooth conditions do not ensure worst case emissions scenarios, which for example with CO is typically at low loads or in rapidly swinging loads, such as when a paper machine goes down or starts up suddenly. Despite EPA's comments to the contrary, periods of start-up, shutdown and malfunction are not represented in "normal operating conditions"; the proposed MACT limits do not account for SSM and therefore the standards should not apply during SSM periods. Instead, EPA should consider work practice standards during periods of SSM.

Response: See the preamble for response to how EPA adjusted CO emission limits and compliance mechanisms, and changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Michael Hutcheson
Commenter Affiliation: Ameren Services
Document Control Number: EPA-HQ-OAR-2002-0058-2803.1
Comment Excerpt Number: 2

Comment: The standards proposed are not all daily or monthly averages as EPA purports. Initial compliance with the standards are based on the average of 3 4-hour stack test runs during a period representative of maximum emissions not daily or monthly averages. Continuing compliance is based on 12-hour block averages of CPMS data for several pollution control equipment configurations required for compliance with the rule. None of the stack test data collected during the ICR includes any startup or shutdown periods and therefore the MACT standards do not reflect the emission limitation achievable by the best performing 12 % of sources during these periods.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Derril Marshall
Commenter Affiliation: Fremont Department of Utilities
Document Control Number: EPA-HQ-OAR-2002-0058-3198
Comment Excerpt Number: 2

Comment: We believe that EPA should be able to identify actual similar boilers that have continuously demonstrated compliance with the proposed MACT limits. We do not believe that EPA has any data from existing similar boilers during normal worst case conditions, under all normal operating variations, under start up shut down or malfunction to support that the best controlled 12% of similar boilers actually meet the emission limitations that are being proposed.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: William Rogers
Commenter Affiliation: DTE Energy
Document Control Number: EPA-HQ-OAR-2002-0058-2966.1
Comment Excerpt Number: 2

Comment: Operations during periods of startup, shutdown and malfunction are different those of steady state operation. Yet, EPA did not require any testing during these periods of upset conditions. EPA suggests that startup and shutdown periods have been taken into account "in establishing the standards in this rule", but there is no demonstration that the best performing units can achieve the proposed MACT limits during periods of startup, shutdown or malfunction. EPA must obtain emission data during these periods and utilize this data while setting MACT emission limits.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Nilaksh Kothari
Commenter Affiliation: Manitowoc Public Utilities
Document Control Number: EPA-HQ-OAR-2002-0058-2810.1
Comment Excerpt Number: 2

Comment: MPU believes the EPA grossly underestimated the impact that SSM will have on a boiler. Boilers have a maximum heat flux rate that may require eight to ten hours to bring a unit up to normal operating temperatures. During the start up phase, emissions such as carbon monoxide (CO) will be significantly elevated, as temperatures are too low for complete combustion. Attached please find a chart depicting CO operating data with the peaks occurring during SSM events. CO emissions will be lower when the boiler is online and stable, however we do not believe it is possible to average out the SSM emissions when operating in the proposed ranges. In addition, in today's energy markets such as the Midwest Independent System Operator (MISO) we believe it could become routine operation for smaller EGU units to shutdown on a daily basis as the energy may not be required at off peak times. These additional SSM events will exacerbate the situation and could force an EGU to leave a unit online even though it is not needed, resulting in unnecessary emissions. We recommend that EPA reevaluate and develop revised emission limits to address the SSM concerns.

Response: See the preamble for response to how EPA adjusted CO emission limits and compliance mechanisms, and changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: A. Preston Howard, Jr
Commenter Affiliation: Manufacturers and Chemical Industry Council of North Carolina
Document Control Number: EPA-HQ-OAR-2002-0058-2706.1
Comment Excerpt Number: 3

Comment: Boiler manufacturers also warn that many of the proposed limits will be impossible to attain during operation that includes startup, shutdown and malfunction (SSM) periods which are unavoidable in normal commercial operation.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Michael Hutcheson
Commenter Affiliation: Ameren Services
Document Control Number: EPA-HQ-OAR-2002-0058-2803.1
Comment Excerpt Number: 3

Comment: US EPA maintains that the CEMS data used to establish standards included periods of startup and shutdown, however there is no indication in the CEMS data available in the record that this is true. In addition, the CEMS data available in the record does not include any liquid fuel boilers and because only CO CEMS were used the data is only representative of CO data. CO data by US EPA's own analysis is not representative of particulate HAPs, Hg, HCL or dioxin/furans. It provides no basis to assume that these other pollutants don't fluctuate significantly during startup, shutdown, malfunction or other transient periods and certainly provides no information on liquid fueled boilers which were not included in the CEMS data collected. US EPA can not definitively state that based on the record, the standards reflect emission rates that are achievable during startups, shutdowns, malfunctions or other transient events by the best performing 12 % of sources. Because US EPA cannot definitively state that, US EPA needs to revise the standards to reflect levels achievable during these periods by either collecting additional data or by exemption.

Response: See the preamble for response to how EPA adjusted CO emission limits and compliance mechanisms, and changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Brad James
Commenter Affiliation: Trinity Consultants
Document Control Number: EPA-HQ-OAR-2002-0058-2853.1
Comment Excerpt Number: 3

Comment: Because bagasse has such a high moisture content, it is not combustible in its natural state. Instead, bagasse first must be dried. Because bagasse naturally absorbs ambient moisture, the combustion process must follow directly after the drying process. As a result, bagasse boilers cannot startup by burning bagasse; another fuel is needed to fire up the boilers to begin the drying phase. U.S. Sugar's bagasse boilers generally use fuel oil until the boilers can run on bagasse, at which point the transition to 100% bagasse is phased in. Fuel oil, of course, has a different emissions profile than bagasse and all other biomass fuels. This results in entirely different emissions, both in type and quantity, during the startup period. Other biomass boilers that burn a dryer fuel available for use at startup may not experience the same degree of disparity between the startup and peak operating periods. Therefore, MACT Floors appropriate to bagasse-fueled boilers can only be determined by considering the unique startup process shared only among other bagasse-fueled boilers. A distinct subcategory is necessary to identify the true best performers among those facing similar challenges.

Response: See the preamble for discussion of combined grate/suspension firing subcategory, which includes bagasse units based on design features. The subcategory is not specific to fuel type. Please see the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Frederick W. Lash
Commenter Affiliation: Air Products and Chemicals, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-3178
Comment Excerpt Number: 3

Comment: No Relief from Emission Limits during Maintenance/Startup/Shutdown and Alternate Operating Modes

The proposed CO emission standards for Gas 2 facilities appear to be based upon emission data from short term stack tests of the best performing sources during periods of high rates and steady state operation. Given the variability of CO emissions during episodes of maintenance, start-up, shutdown, variable production demands, stand-by operating modes, etc., even processes with the lowest combustion emissions cannot comply with the proposed emissions limits all the time.

Not allowing any exemptions or considerations for multiple operating modes under the proposed rule is inappropriate when no source can attain 100 % compliance.

Recommendation: The agency is requested to consider relief for such operations by 1). establishing more representative emission limits for such operations and 2). allowing longer averaging times in conjunction with more representative emission limits, or 3). using good work practices to minimize emissions instead of prescribing numerical standards.

Response: See the preamble for response to how EPA adjusted CO emission limits and compliance mechanisms, and changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Nilaksh Kothari
Commenter Affiliation: Manitowoc Public Utilities
Document Control Number: EPA-HQ-OAR-2002-0058-2810.1
Comment Excerpt Number: 3

Comment: The DC Circuit's December 29, 2008 holding in the Sierra Club case that struck down a general Start Up / Shut Down & Malfunction (often referred to as SSM) exemption applicable to Section 112 MACT standards. The court held that a generic SSM exemption based on the general duty clause was overbroad and that compliance with a MACT had to be continuous.

Nonetheless, EPA must still recognize that SSM events will occur and must develop MACT emission limitations that take into account the elevated emission rates which occur during these unavoidable periods. The ICI Boiler MACT standard must be crafted such that the limits can be met continuously, 100% of the time, including during SSM events.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Wayne J. Galler and Deborah A. Phillips
Commenter Affiliation: Georgia Industry Environmental Coalition, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2882.1
Comment Excerpt Number: 3

Comment: The emissions standards proposed in EPA's Boiler MACT Rule are meant to apply during normal operations as well as during periods of "Start-up, Shutdown, or. Malfunction (SSM)". However, in many cases, EPA utilized the results from stack tests (ICR phase II) that were based on three, one-hour runs, to set the MACT floor. These tests did not in most cases, represent emissions achieved during SSM periods. As a result, the proposed MACT standards are based on boilers operating under steady-state conditions, and we:believe, are unachievable during SSM periods. Many boilers experience extended periods of start-up, lasting anywhere from 18 to 24 hours, or longer. During the start-up period, boilers may switch fuels (e.g., fuel oil may be used to warm-up a coal-fired boiler) and alter the amount of combustion air fed into the combustion chamber in order to attain steady-state operations. It takes a considerable length of time for large boilers to reach steady-sate conditions, and as a result, emissions will in most cases, be higher during the start-up phase of operations. Malfunction episodes are unpredictable and the resulting emissions during these periods are usually much higher than during normal operations.

Therefore, GIEC urges EPA to consider work place standards during SSM periods in lieu of establishing specific numerical limitations. Emission rates from industrial boilers during SSM periods will vary greatly depending upon a number of operating variables as well as the type of boiler, and therefore, emission limitations cannot easily be established. GIEC believes that it makes more sense to require work place standards that minimize emissions to the extent practicable during SSM periods until such time that the boiler is either (1) placed into normal steady-state operation, (2) safely shut down, or, (3) returned to normal operation by taking corrective action to resolve the malfunction.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 4

Comment: EPA's lack of treatment for startup and shutdown periods is also of concern. Averaging times alone will not be enough to allow sources to meet the proposed standards during startup and shutdown. We provide detailed comments on why these periods should be considered separately from normal operation and believe that work practices such as following an emissions minimization plan are appropriate for startup, shutdown and malfunction conditions.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Terry Walmsley
Commenter Affiliation: Fibrowatt LLC
Document Control Number: EPA-HQ-OAR-2002-0058-2995.1
Comment Excerpt Number: 4

Comment: As stated in the Major Source Boiler Rule at 32050 and the Area Source Boiler Rule at 31926, a source must meet emission standards at all times during the operation of the plant, therefore this presumably would uniformly include during periods of Startup, Shutdown, and Malfunction ("SSM") . While EPA suggests that a uniform emission limit can encompass normal SSM, Fibrowatt believes that continuous compliance can be adversely impacted by a truncated daily averaging period. Fibrowatt further believes that this requirement can have practical problems associated with normal transitions through periods of SSM and supports an approach that would stipulate an alternative but enforceable limit during periods of startup and shutdown as opposed to a single uniform limit. Fibrowatt further requests that EPA provides more definitive guidelines on how periods of malfunction will be appropriately addressed in the rules and address emission limit applicability during such unpredictable occurrences.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Michael Hutcheson
Commenter Affiliation: Ameren Services
Document Control Number: EPA-HQ-OAR-2002-0058-2803.1
Comment Excerpt Number: 4

Comment: US EPA also apparently maintains that because boilers "normally" do not startup and shutdown daily so it isn't important for the standards to reflect SSM periods. Whether or not boilers startup and shutdown daily, however, is irrelevant to the standards setting process. US EPA boldly professes that these periods are "routine operations" and if this is the case, the standards should reflect emission rates that the best performing boilers are able to achieve during these "routine operations". US EPA states it believes boilers can meet these standards during startup and shutdown periods, but provides no data which supports that argument. US EPA needs to provide actual data to support its claims that the best performing sources meet these standards during startups, shutdown and/or malfunction periods.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Paul J. Allen
Commenter Affiliation: Constellation Energy
Document Control Number: EPA-HQ-OAR-2002-0058-3164
Comment Excerpt Number: 4

Comment: Establish limits that take start up and shut down into account, exempt start up and shut down or establish separate start up and shut down standards since these operating periods have different emission profiles. Existing permit limits allow for emissions during start-up and shutdown. Most power plants have CO limits specific to startup and shutdown events, when emission concentrations are higher for a short period of time until normal operating conditions are achieved, complete combustion is occurring, and the control equipment commences and stabilizes as designed. CO standards in the proposed Boiler MACT Rule do not accommodate for this. We suggest that existing permit limits be used for these periods.

Response: See the preamble for response to how EPA adjusted CO emission limits and compliance mechanisms, and changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Tim Hagley
Commenter Affiliation: Minnesota Power
Document Control Number: EPA-HQ-OAR-2002-0058-2829.1
Comment Excerpt Number: 4

Comment: Separate Emissions Standards Should Be Developed for Periods of Startup, Shutdown and Malfunction. Emissions of some HAPS are more difficult to control during startup, shutdown and malfunction (SSM) conditions, particularly in boilers that co-fire biomass with coal. EPA's assertion that "[t]he standards we are proposing are daily or monthly averages..." implies that the longer averaging periods will be able to absorb any higher emission rate during the SSM period, is flawed. For example, startups can take the greater part of a day, likely resulting in exceedances of any daily standard, even though all efforts are taken to remain in compliance. A higher emission rate during startup may not result in high mass emissions due to the lower startup fuel feed rates, so a significant environmental impact should not be expected. Consideration should be given for separate emission standards during startup, shutdown and malfunction periods that take into consideration the relatively low mass emissions during those periods.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Daniel Moss
Commenter Affiliation: Society of Chemical Manufacturers and Affiliates
Document Control Number: EPA-HQ-OAR-2002-0058-2926.1
Comment Excerpt Number: 5

Comment: The data on which EPA relies are not representative of either the universe of regulated boilers or the variability inherent in normal operations, including startup and shutdown.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Terry Walmsley
Commenter Affiliation: Fibrowatt LLC
Document Control Number: EPA-HQ-OAR-2002-0058-2995.1
Comment Excerpt Number: 5

Comment: Under normal and predictable startup operations, a requirement to continuously meet uniform emission limits may be difficult for certain types of biomass fuels as the unit progresses through the normal transition from startup fuel to biomass fuel. Although Fibrowatt utilizes a low emission startup fuel (expected to be propane) and it is reasonable to maintain emission standards while on startup fuel, the switch from propane to certain biomass fuels in a spreader=stoke boiler can typically result in a significant variation in carbon monoxide (CO) emissions that can adversely effect the CO average (especially during truncated daily operations) and therefore compliance demonstration. Including such startup period in the normal compliance determination for CO may not be achievable under all conditions and all biomass fuels where the normally startup period can run for a long period of time, for example during a "cold=start ."

Response: See the preamble for response to how EPA adjusted CO emission limits and compliance mechanisms, and changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Caroline Choi
Commenter Affiliation: Progress Energy
Document Control Number: EPA-HQ-OAR-2002-0058-2868.1
Comment Excerpt Number: 5

Comment: The IB ICR did not require any testing during start-up, shutdown and malfunction events. Without emissions data during these periods, EPA has no factual basis for concluding that the best performing units can achieve the proposed MACT limits during start-up, shutdown and malfunction events. Operations during boiler start-ups are different than normal plant operations. Certain plant components must be started in a specific sequence in order to ensure that steady state operations can be achieved. During start-up not all pieces of control equipment will be operating at peak efficiency. Progresss Energy believes that work practice standards are far more appropriate during periods of start-up, shutdown and malfunction.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Derril Marshall
Commenter Affiliation: Fremont Department of Utilities
Document Control Number: EPA-HQ-OAR-2002-0058-3198
Comment Excerpt Number: 5

Comment: For periods of startup and shutdown, we request that EPA consider a mass limit (lb/hr) equivalent to the lb/MMBtu or ppm concentration based limit at maximum load. The health effects due to HAP emissions are no worse or better during startup than at full load based on the same mass emission rate, however this is one way that real world compliance could be assured. This approach is commonly used in setting PSD limitations that govern startup and shut down.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Nilaksh Kothari
Commenter Affiliation: Manitowoc Public Utilities
Document Control Number: EPA-HQ-OAR-2002-0058-2810.1
Comment Excerpt Number: 5

Comment: Designing a control system to handle the start up emissions of boilers would require an additional major investment in controls and energy with only limited use. It is certainly possible that a control system designed to handle start up / shut down emissions could create more pollution than it would prevent. We also believe that the start up / shut down limitations will require additional procedures that could delay bringing a unit online and unintended consequences could result from this action. In addition, we believe it will be very difficult to demonstrate compliance during start up / shut down periods as conditions continuously and rapidly change as the boiler comes up on load and stabilizes.

Response: See the preamble for response to how EPA adjusted compliance mechanisms, and changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Tom Midyett
Commenter Affiliation: Tennessee Paper Council
Document Control Number: EPA-HQ-OAR-2002-0058-2691.1
Comment Excerpt Number: 6

Comment: We are very concerned that EPA proposal does not set a separate standard for periods of startup, shutdown, and malfunction. On the one hand, EPA asserts that “[t]he standards we are proposing are daily or monthly averages … [t]hus, we are not establishing separate emission standards for these periods because startup and shutdown are part of their routine operations and, therefore, are already addressed by the standards.” [75 Fed. Reg. at 32013.] On the other hand, EPA uses short term performance test results to set the standards rather than the results of long-term CEMS monitoring. As a result, the emissions data on which the standards are based do not, in fact, reflect or adequately accommodate emissions from periods of startup, shutdown, or malfunction.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Jim Weeks
Commenter Affiliation: Michigan Municipal Electric Association
Document Control Number: EPA-HQ-OAR-2002-0058-2795.1

Comment Excerpt Number: 6

Comment: Standards that Reflect CO Emissions Variability — The standards set for CO emissions from electric utility units should be amended to reflect the extreme variability of CO output under standard utility unit operations. CO emissions can vary and increase during periods of start-up, shut-down and limited use of the electric units. however, EPA's proposed rule does not account for such CC) variability nor propose separate emissions limitations for periods of start-up, shut-down and other operating, load and fuel-mix variability at these units.

Response: See the preamble for response to how EPA adjusted CO emission limits and compliance mechanisms, and changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Terry Walmsley
Commenter Affiliation: Fibrowatt LLC
Document Control Number: EPA-HQ-OAR-2002-0058-2995.1
Comment Excerpt Number: 6

Comment: Furthermore, the Major Source Boiler Rule at 32013 and the Area Source Boiler Rule at 31901 suggest that emissions during malfunction events would represent an alternative operating mode but does not resolve how this alternative operating mode would be adequately dealt with in the proposed rule. While the supporting language in the Major Source Boiler Rule at 32013 and the Area Source Boiler Rule at 31902 suggest that EPA will determine an appropriate response to the malfunction event, this is not adequately addressed in the proposed Major Source Boiler Rule and the Area Source Boiler Rule as it relates to limit applicability "at all times."

Fibrowatt requests that EPA better=defines its "appropriate response" to malfunction events so regulated parties under the Major Source Boiler Rule and the Area Source Boiler Rule can properly evaluate measures required during such malfunction events. Fibrowatt further requests an additional comment period be given for regulated parties to assess what EPA establishes as good operating practices during malfunction events and associated consequences to EPA's "appropriate response" to such events.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Joe Muehlbach
Commenter Affiliation: Quad/Graphics
Document Control Number: EPA-HQ-OAR-2002-0058-2898.1
Comment Excerpt Number: 6

Comment: EPA must provide flexibility during start-up and shut down of the boilers when there can be compliance issues that are due simply to the action of turning on or shutting off the boiler. Removing this flexibility will only serve to catch an otherwise compliant boiler with relatively small exceedences that are only present due to the nature of the start-up or shut-down and not indicative of how that boiler performs during hours of normal operation.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Gene Barr
Commenter Affiliation: Pennsylvania Chamber of Business and Industry
Document Control Number: EPA-HQ-OAR-2002-0058-3161
Comment Excerpt Number: 7

Comment: The proposed cm: ssion limits are based on the best demonstrated control level from test results Airing normal operation, without regard for varying operational phases, particulat start-up, shutdown and maintenance phases.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Chris Welch
Commenter Affiliation: Colorado Springs Utilities
Document Control Number: EPA-HQ-OAR-2002-0058-2943.1
Comment Excerpt Number: 7

Comment: Within the proposed rule, Ill. Summary of This Proposed Rule, E. What are the startup, shutdown, and malfunction (SSM) requirements, is the following statement, "In establishing the standards in this rule, EPA has taken into account startup and shutdown periods and, for the reasons explained below, has not established different standards for those periods. The standards that we are proposing are daily or monthly averages."

Which standards are monthly averages, which are daily? Are they rolling or block averages? Do periods of downtime get included in these averages?

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: John M. Irving
Commenter Affiliation: Burlington Electric Department

Document Control Number: EPA-HQ-OAR-2002-0058-2954.1
Comment Excerpt Number: 7

Comment: No provisions for startup, shutdown, or malfunction of any kind are not reasonable and will result in large quantities of data flowing into the EPA.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Catherine W. McCuthen
Commenter Affiliation: Blue Heron Paper Company
Document Control Number: EPA-HQ-OAR-2002-0058-2892.1
Comment Excerpt Number: 7

Comment: The proposed rules provide no recognition of the elevated emissions levels associated with the startup of biomass boilers. In the proposed rule EPA grants no recognition of the realities of biomass boiler startups, imposing the standards applicable to normal operation to days where startups occur. The only recognition of the anomalous conditions that exist during startup was to state that 24 hours averaging would enable boiler operators to demonstrate compliance notwithstanding startup. For example, startups with ESPs can routinely take 6 to 8 hours and opacity, as recorded by a continuous opacity monitor, can reach 90 percent. It is known that not all of those readings accurately reflect opacity as considerable moisture is driven off the kindling fuel and the interior surfaces of the boiler, resulting in water vapor that is inaccurately read as opacity. However, there is also significant opacity during startup that is not capable of being reduced as the control equipment cannot be energized until the moisture is driven off and the interior surfaces adequately warmed up. Rushing this process can result in damage to control equipment and explosion concerns. As a result, notwithstanding good operation, it is mathematically impossible to average the startup opacity conditions with the opacity once normal operations have commenced to comply with a 10 percent opacity standard applicable to those biomass boilers employing ESPs or scrubbers (the vast majority of the controlled boilers in this subcategory).

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Steve Zika
Commenter Affiliation: Hampton Lumber Mills, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2817.1
Comment Excerpt Number: 7

Comment: After reading the proposed standards, we understand that EPA believes that a source will not have any problems with demonstrating compliance with CO emissions using a 30-day rolling average. Hampton agrees with this as long as emissions during start-up, shut down, and malfunction are not used in the calculation of the 30-day rolling average. Hampton operates CEMS continuously and has data collected during startups which show that best management practices for controlling CO emissions under normal operations do not work during a startup. Additionally, start-up and shutdown periods are not reflective of normal operating conditions, or anywhere near the 90 percent of load that the standard was based upon. Therefore Hampton believes that a start-up, shutdown, or malfunction is not normal operations and therefore the emissions should not be used when calculating compliance with a daily or monthly average. Most of our shutdowns and start-ups relate to difficult market conditions wherein the entire sawmill is shut down for a period of time until customer demand returns. We believe this will continue during the economic recovery and into the future.

Response: See the preamble for response to how EPA adjusted CO emission limits and compliance mechanisms, and changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Catherine W. McCuthen
Commenter Affiliation: Blue Heron Paper Company
Document Control Number: EPA-HQ-OAR-2002-0058-2892.1
Comment Excerpt Number: 8

Comment: We strongly encourage EPA to develop a startup exception to compliance with the work practice standards. Other recently promulgated NESHAPs have recognized that it is impossible to demonstrate compliance with emission standards during startup conditions and have allowed sources a reasonable period where they do not need to demonstrate compliance with the limits. For example, the Subpart ZZZZ NESHAP allows natural gas and diesel fired engines a 30 minute startup period during which the standards do not apply. If this can be allowed for fossil fuel fired units such as reciprocating internal combustion engines, a similar approach should be recognized for biomass boilers. Therefore, we recommend that EPA revise the rules to allow an 8 hour startup period during which the limits do not apply. Because this time may not be adequate for startup of some larger boilers without any supplementary fuel capability, we also suggest that EPA clarify that sources can apply to EPA for a longer startup time period.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Robert E. Cleaves
Commenter Affiliation: Biomass Power Association
Document Control Number: EPA-HQ-OAR-2002-0058-2934.1
Comment Excerpt Number: 8

Comment: A significant problem, as will be noted by others, is that the emission standards make no accommodation for startup and/or shutdown.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Paul N. Cicio
Commenter Affiliation: Industrial Energy Consumers of America
Document Control Number: EPA-HQ-OAR-2002-0058-2752.1
Comment Excerpt Number: 8

Comment: EPA established the MACT floor limits based on testing conducted at steady state (and high load) conditions, so it cannot directly apply the data to startup, shutdown and malfunction (SSM) conditions.
The boiler MACT rule requires sources to maintain compliance with the same standards during startup, shutdown and malfunction (SSM) conditions as during normal full load conditions. However, EPA did not consider the expected variability in emissions during SSM and low loads when setting the standards. Without this variability in the standards, even the best performing sources are likely to be unable to comply under SSM or changing load conditions.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Mick Baranko
Commenter Affiliation: Douglas County Forest Products
Document Control Number: EPA-HQ-OAR-2002-0058-2856.1
Comment Excerpt Number: 8

Comment: The proposed rules provide no recognition of the elevated emissions levels associated with the startup of biomass boilers. In order to safely start up a biomass boiler without risk of causing explosion and avoid undue stress to the boiler, it is necessary to heat up the boiler slowly and without the benefit of particulate controls. EPA has recognized that until combustion is stable and the boiler has reached an exhaust temperature of 250F, it is not safe to energize an ESP. This fact has been recognized in prior rules such as the Boiler NSPS. In the proposed rule EPA grants no recognition of the realities of biomass boiler startups, imposing the standards applicable to normal operation to days where startups occur. The only recognition of the anomalous conditions that exist during startup was to state that 24 hours averaging would enable boiler operators to demonstrate compliance notwithstanding startup. This is grossly inaccurate. Startups can routinely take 6 to 8 hours and opacity, as recorded by a continuous opacity monitor, can reach 90 percent. It is known that not all of those readings accurately reflect opacity as considerable moisture is driven off the kindling fuel and the interior surfaces of the boiler, resulting in water vapor that is inaccurately read as opacity. However, there is also significant opacity during startup that is not capable of being reduced as the control equipment cannot be energized until the moisture is driven off and the interior surfaces adequately warmed up. Rushing this process can result in damage to control equipment and explosion concerns. As a result, notwithstanding good operation, it is mathematically impossible to average the startup opacity conditions with the opacity once normal operations have commenced to comply with a 10 percent opacity standard applicable to those biomass boilers employing ESPs or scrubbers (the vast majority of the controlled boilers in this subcategory).

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Richard Rosvold
Commenter Affiliation: Xcel Energy Services, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2955.1
Comment Excerpt Number: 8

Comment: The EPA intends to have the emission limits apply at all time periods, including during startup and shutdown. EPA's justification for this is that the limits are considered daily or monthly averages, and thus any spikes experienced during startup and shutdown would be smoothed out in the averaging. This is explained on page 32012 in the preamble to the rule, but not in the regulation itself.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: W. Phillip Reese
Commenter Affiliation: California Biomass Energy Alliance
Document Control Number: EPA-HQ-OAR-2002-0058-2774.1
Comment Excerpt Number: 8

Comment: EPA makes a similar mistake with regard to its proposal not to set a separate standard for periods of startup, shutdown, and malfunction (SSM). On the one hand, EPA asserts that "[t]he standards we are proposing are daily or monthly averages ... [t]hus, we are not establishing separate emission standards for these periods because startup and shutdown are part of their routine operations and, therefore, are already addressed by the standards." On the other hand, EPA uses short term performance test results to set the standards rather than the results of longterm CEMS monitoring. Occurrences of malfunctions are entirely unpredictable, in terms of when, for what reason, and for how long. Therefore, inclusion of emission limitations for malfunction cannot be justified on any technical basis. All permits in California have specific provisions for malfunction, which should be respected and replicated by the EPA. As a result, the emissions data on which the standards are based do not, in fact, reflect or adequately accommodate emissions from periods of startup, shutdown, or malfunction, if such SSM periods are intended to be covered by the emission limitations.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Brad James
Commenter Affiliation: Trinity Consultants
Document Control Number: EPA-HQ-OAR-2002-0058-2853.1
Comment Excerpt Number: 9

Comment: EPA has proposed to include startup and shutdown in the same MACT standard as peak operations. This result is neither reasonable nor required by case law.

In Sierra Club v. EPA, 551 F.3d 1019 (D.C. Cir. 2008), cert. denied, 130 S. Ct. 1735 (201), the D.C. Circuit held that EPA could not exempt periods of startup and shutdown from MACT standards. The court based its holding on CAA's requirement that the MACT standards apply continuously. Id. at 1027-28 (discussing interaction between sections 112(d) and 302(k)). The court did not, however, hold that the MACT standards for periods of startup and shutdown must equal the MACT standards during peak operations, or that there be one uniform MACT standard that applies during all periods. To the contrary, the court observed that that section 302(k) does not "necessarily" require "continuously applying a single standard." Id. at 1027. The court merely held that some MACT standard must apply during periods of startup and shutdown.

The best way to control for the differences between startup and shutdown periods and peak operation periods is to have one MACT standard govern startup and shutdown and another MACT standard govern peak operations. Such a result clearly would not run afoul of Sierra Club's holding because MACT standards will apply continuously during boiler operations.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Dell Majure
Commenter Affiliation: Kimberly Clark Corp.
Document Control Number: EPA-HQ-OAR-2002-0058-2779.1
Comment Excerpt Number: 9

Comment: To assure that startup, shutdown, and malfunction are appropriately accommodated, EPA must assure that the data on which the standard is based include representative data from such periods.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Mick Baranko
Commenter Affiliation: Douglas County Forest Products
Document Control Number: EPA-HQ-OAR-2002-0058-2856.1
Comment Excerpt Number: 9

Comment: We strongly encourage EPA to develop an exception to compliance with startup work practice standards. Other recently promulgated NESI1APs have recognized that it is impossible to demonstrate compliance with emission standards during startup conditions and have allowed sources a reasonable period where they do not need to demonstrate compliance with the limits. For example, the Subpart ZZZZ NESHAP allows natural gas and diesel fired engines a 30 minute startup period during which the standards do not apply. If this can be allowed for fossil fuel fired units such as reciprocating internal combustion engines, a similar approach should be recognized for biomass boilers. Therefore, we recommend that EPA revise the rules to allow an 8 hour startup period during which the limits do not apply. Because this time may not be adequate for startup of some larger boilers without any supplementary fuel capability, we also suggest that EPA clarify that sources can apply to EPA for a longer startup time period.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Christopher S. Colman
Commenter Affiliation: Hovensa LLC
Document Control Number: EPA-HQ-OAR-2002-0058-2863.1
Comment Excerpt Number: 9

Comment: Many commenters have addressed the need for a separate standard for startup, shutdown and malfunction periods. HOVENSA supports those comments, particularly for malfunctions where the proposed rule affords no relief whatsoever despite a requirement for MACT standards to be met “continuously.” HOVENSA notes that while the DC Circuit struck down the general SSM work practice standard in 40 CFR 63.6, the court’s opinion in Sierra Club appears to invite EPA to adopt similar standards for SSM events under Section 112(h). HOVENSA urges EPA to adopt an SSM work practice standard essentially similar to 63.6(e), particularly for petroleum refineries because of process variability discussed below. This variability is even more significant for island/non-continental facilities.

Response: See the preamble for discussion of the non-continental unit subcategory and changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Edward E. Quick
Commenter Affiliation: Celanese International Corp
Document Control Number: EPA-HQ-OAR-2002-0058-2840.1
Comment Excerpt Number: 9

Comment: EPA has proposed standards that are not technically achievable by not considering operation during startup, shutdown and malfunction (SSM) or changes in rate when establishing the emission standards.
The proposed rule requires affected sources to maintain compliance during startup, shutdown and malfunction (SSM). However, when developing the proposed rule, EPA considered SSM only when developing the CO emissions standard for coal fired sources and, as such, is only achievable for those coal fired sources.

Emissions of other pollutants (PM, mercury, HCl, and D/F) are just as likely to increase during periods of SSM. Both combustion and pollution control device performance are variable during SSM and changes in rate.

The MACT floor for pollutants other than CO was established based on emission testing conducted at steady-state, high load conditions. These conditions may be achievable during a three-run emissions test, but not during all operating conditions.
In order to properly consider SSM and not only steady-state conditions, EPA must either:
-apply the emission standards at all times except during SSM and allow work practice standards to be implemented during SSM, or
-consider periods of SSM in the MACT floor analysis, and implement all emissions standards on a 30-day rolling average basis (this would incorporate rate changes for boilers and process heaters).
Because of the cost of continuous HCl and mercury monitoring systems, most affected sources would likely demonstrate compliance using parametric monitoring systems. There is no technical justification that would prevent an affected source from demonstrating compliance on a 30-day rolling average, whether continuous emissions monitors or continuous parametric monitoring systems are used.

Response: See the preamble for response to how EPA adjusted CO emission limits and compliance mechanisms, and changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Paul N. Cicio
Commenter Affiliation: Industrial Energy Consumers of America
Document Control Number: EPA-HQ-OAR-2002-0058-2752.1
Comment Excerpt Number: 10

Comment: Emissions of all regulated pollutants are likely to increase during periods of SSM. Combustion and pollution control device performance both are variable during SSM and changes

in rate. While EPA surely understands that even top performing units suffer malfunctions, the small snapshot of data used by EPA to determine these emission standards do not take these events into account. If the emissions standards are applied at all times including SSM, the MACT floor analysis must consider emissions data taken during those periods.
For example, numerous units currently operate with Carbon Monoxide (CO) Continuous Emissions Monitoring Systems (CEMS). IECA encourages EPA to collect CO data from sources equipped with CO CEMS, and analyze the data and especially the effect of Startups, Shutdowns and Malfunctions. EPA should revise its standards to account for the significant variability that occurs during SSMs by either:
(1) Establishing a work practices standard instead of an emissions standard to minimize emissions of CO during SSMs, or
(2) Establishing a separate CO emissions standard that would apply during SSMs, which would reflect the real variability in CO emissions during these events, or
(3) Raising the CO average emission standard so that sources can comply when SSM data is included.

Response: See the preamble for response to how EPA adjusted CO emission limits and compliance mechanisms, and changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Brad James
Commenter Affiliation: Trinity Consultants
Document Control Number: EPA-HQ-OAR-2002-0058-2853.1
Comment Excerpt Number: 10

Comment: In the context of bagasse boilers, a separate MACT treatment for startup and shutdown is far more appropriate than the current approach. Due to the high moisture content of bagasse that requires drying before it can be used as fuel, bagasse-fueled boilers require a different fuel source and unique operating procedures during the startup process. This alternate fuel source possesses a completely distinct emission profile than bagasse. Accordingly, the MACT Floor applicable to bagasse boilers during peak operations should differ from that applicable during the startup period.

However, EPA’s proposed MACT standard applies during all modes of operation including startup and shutdown, but was not based on any data collected during startup or shutdown, or other “adverse circumstances which can reasonably be expected to recur.” This further invalidates the proposed standards as they were not “achieved under the worst foreseeable circumstances.”

Response: See the preamble for discussion of a combined grate/suspension firing subcategory. The subcategory includes bagasse units, however is based on design features and is not specific to fuel type. See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Eveleen Muehlethaler
Commenter Affiliation: Port Townsend Paper Corp
Document Control Number: EPA-HQ-OAR-2002-0058-2871.1
Comment Excerpt Number: 10

Comment: We recommend that EPA reconsider the Boiler rule to include SSM language for Start-up, Shut-down and Malfunctions.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Richard Rosvold
Commenter Affiliation: Xcel Energy Services, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2955.1
Comment Excerpt Number: 10

Comment: We question the validity of establishing limits during startup and shutdown in this manner.. For example, CO emissions spike during periods of startup and shutdown, often to levels that are orders of magnitude greater than the average values achieved during normal operation. The magnitude of these spikes is so severe in comparison to the limit, that we doubt any existing units would be able to meet a limit of 1 ppm. And while it is true, as EPA states on page 32013 of the preamble, that solid fuel boilers do not normally start up and shut down more than once per day, liquid fuel-fired boilers have that capability. Imposition of such severe limits would eliminate that operating scenario.
Also, there are many units that are primarily run to test the unit's operating capabilities. These units are run for only a short time at high loads in a given operating run. The high concentrations during startup and shutdown severely skew the average concentrations. This also creates issues with compliance demonstration, as for many units, compliance is demonstrated with the average of three 1-hour long stack tests using EPA Method 10 conducted at maximum operating load. This testing method was not developed with startup and shutdown operations in mind.

Response: See the preamble for response to how EPA adjusted CO emission limits and compliance mechanisms, and changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Gary Melow
Commenter Affiliation: Michigan Biomass
Document Control Number: EPA-HQ-OAR-2002-0058-2776.1
Comment Excerpt Number: 11

Comment: EPA has mandated that the proposed emission standards apply at all times, including startup and shutdown. EPA reasons (75 FR at 32012-32013) that the daily or monthly averages take these episodes into account. There appears to be a mathematical problem in using concentration levels corrected to an O2 level under startup conditions. Elevated O2 levels seen during startup result in highly inflated PPM values (we refer to this as "data blowup") that cannot be compensated for in a longer averaging time. For example, in the first hour of startup when the O2 levels are near ambient levels, the O2 correction calculations provided for in Method 19 of 40 CFR 60 Appendix B yield invalid numbers. If the O2 monitor reads 20.9% (common for the first hour in startup), the emissions in corrected PPM is equal to infinity. If the O2 monitor reads 21% at the beginning of a startup (possible, given the accuracy of the instrument) the corrected PPM value will be a huge negative number. The excessively high PPM corrected values will continue for the first couple hours of startup and it will take up to 10 hours before the O2 level reaches a level close to 7%, at which point the mathematical "penalty" will stop. The same can occur in a shutdown, although for a shorter amount of time. These very high corrected values occur even when actual emissions are quite small. No averaging time will compensate for the extremely high values seen when using a concentration corrected to a given percentage of O2 during this time. We have corrected our operating permits in all cases that eliminates the use of a PPM corrected value (or a lb/MMBtu value, which in Method 19 carries the same mathematical problem see equations 19-1 to 19-3) during startup or shutdown conditions. We instead rely on mass emission rate values, which is practical on a unit-by-unit basis considering actual size.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Paul N. Cicio
Commenter Affiliation: Industrial Energy Consumers of America
Document Control Number: EPA-HQ-OAR-2002-0058-2752.1
Comment Excerpt Number: 11

Comment: EPA does not provide sufficient justification for the averaging times used to demonstrate compliance with the HCl and mercury emission limits.
Because of the variability in fuels and fuel quality, the requirement to demonstrate compliance during SSM conditions, and the inaccuracy of compliance measurement methods, the proposed approach is not acceptable. In light of this, the emissions limits for PM, HCl, and mercury limitations should be enforced on a 30-day rolling average. Because of the cost of continuous HCl and mercury monitoring systems, most affected sources would likely demonstrate compliance using parametric monitoring systems. There is no technical justification that would prevent an affected source from demonstrating compliance on a 30-day rolling average, whether continuous emissions monitors or continuous parametric monitoring systems are used. Since emissions testing results were not representative of the full range of operating conditions, such as SSM, the 3 hour test results cannot be used to set standards across the full range of operating conditions. If EPA chooses to set the standard across this range of operating conditions, longer averaging times minimize the compliance impact without impacting the overall emissions released to the environment.

As an alternative to applying the emissions standards on a 30-day rolling average, EPA may apply the emission standards at all times except during SSM and allow work practice standards to be implemented during SSM.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Richard L. Killion
Commenter Affiliation: Babcock and Wilcox Power Generation Group
Document Control Number: EPA-HQ-OAR-2002-0058-2722.1
Comment Excerpt Number: 11

Comment: Before setting a national standard that includes SSM in a 30-day rolling average, the EPA should collect a minimum of 30 days of continuous data, including SSM periods, and use that data to set the standard.

If the emissions limits are to include SSM, then the units that are setting the limits should be continuously monitored for CO and PM to determine the impact to the stack test average. Of the six units that were continuously monitored for CO, the CO was considerably higher for units that had SSM conditions included in their data sets. No units were continuously monitored for PM as is proposed by the EPA. Table 1 illustrates the impact of SSM on CO readings. [See submittal for Table 1, EPA data related to continuous monitoring of CO.]

The data tabulated illustrates the potential impact of including SSM conditions for CO on solid fuels only. The impact on liquid and gaseous fuels cannot be ascertained due to a lack of data. For three units, continuously monitored and including SSM conditions, the CO is considerably higher than that of the stack test data.

Response: See the preamble for response to how EPA adjusted CO emission limits and compliance mechanisms, and changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Brad James
Commenter Affiliation: Trinity Consultants
Document Control Number: EPA-HQ-OAR-2002-0058-2853.1
Comment Excerpt Number: 11

Comment: EPA states that they have taken into account startup and shutdown periods. See 75 Fed. Reg. 32,012-32,013, ("In establishing the standards in this rule, EPA has taken into account startup and shutdown periods and, for the reasons explained below, has not established different standards for those periods. The standards that we are proposing are daily or monthly averages. Continuous emission monitoring data obtained from best performing units, and used in establishing the standards, include periods of startup and shutdown"). This statement is false. EPA claimed these were the "best performing units", when they meant "best performing unit for that pollutant only" as EPA's proposed standards for other pollutants were based on all different units (see previous comment). Further, the data utilized for establishing the standards in fact does not include startup and shutdown. In establishing the CO MACT standard for biomass suspension burners / dutch ovens, EPA relied on the following two sets of data: 1) One-time, short term stack test data for suspension burners / dutch ovens firing biomass during normal operation, and 2) Continuous emissions monitoring system (CEMS) data for a single biomass suspension burner during a period of fluctuations in load (i.e., 17% - 77% capacity).

The one-time, short term stack test data (the bulk of the emissions data reviewed) did not include startup or shutdown. And the single set of CEMS data which EPA specifically points to in the proposed Boiler MACT also does not include any data below 17% load – never going to zero which would be representative of a startup and shutdown, not to mention the use of alternate fuels specific to startup (as required for bagasse boilers).

While it is well documented that CO emissions are higher during periods of startup than during normal operation, it should not be the only pollutant considered to have potentially higher startup and shutdown emissions. Most control devices are not designed to be at their peak efficiency except during normal operation, and many cannot be operated during startup for safety reasons. Because EPA has established standards based on data the relies on the reductions of other pollutants from these control devices operating only at peak efficiency during normal operation, they have also erred in establishing "achievable" standards during startup and shutdown for all pollutants.

Therefore, EPA cannot claim that extending the averaging period for CO only should accommodate these routine and expected modes of operation without data showing as such. EPA has performed no such analysis to demonstrate that all standards set are achievable "under most adverse circumstances." The standards were based on data from limited, one-time, short-term stack tests during normal operation that are neither the same averaging period, the same monitoring requirements (stack testing vs. CEMS), nor encompassing of the "adverse circumstances which can reasonably be expected to recur." EPA has instead established arbitrary standards based on narrow data and incorrect assumptions.

Only by gathering data specific to the startup and shutdown periods can a suitable MACT Floor be determined. EPA should gather this data and then propose separate emission standards relevant to the unique characteristics of these periods.

Response: See the preamble for response to how EPA adjusted CO emission limits and compliance mechanisms, and changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Bill Wemhoff
Commenter Affiliation: National Rural Electric Cooperative Association

Document Control Number: EPA-HQ-OAR-2002-0058-2835.1
Comment Excerpt Number: 12

Comment: The IB ICR did not require any testing during start-up, shutdown and malfunction events. Without emissions data during these periods, EPA has absolutely no factual basis for concluding that the best performing units can achieve the proposed MACT limits during these events. For example, operations during boiler start-ups are different than normal plant operations. Certain plant components must be started in a specific sequence in order to ensure that steady state operations can be achieved. During start-up not all pieces of control equipment will be operating at peak efficiency. NRECA believes work practices standards are far more appropriate during these periods. Similarly, for the same reasons, work practice standards are also more appropriate for shutdown and malfunction events.

If EPA insists, however, on setting emission limits for these periods of operation then the agency must obtain emission data during these periods of operation and properly analyze those data in order to set MACT emission limits.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Lee B. Zeugin
Commenter Affiliation: Utility Air Regulatory Group
Document Control Number: EPA-HQ-OAR-2002-0058-2880.1
Comment Excerpt Number: 12

Comment: The IB ICR did not require any testing during start-up, shutdown and malfunction events. Without emissions data during these periods, EPA has absolutely no factual basis for concluding that the best performing units can achieve the proposed MACT limits during start-up, shutdown and malfunction events. See 75 Fed. Reg. at 32,012-13. Operations during boiler start-ups are different than normal plant operations. Certain plant components must be started in a specific sequence in order to ensure that steady state operations can be achieved. During start-up not all pieces of control equipment will be operating at peak efficiency. Furthermore, manual compliance monitoring methods may not provide accurate measurements during start-up conditions. Work practices standards are far more appropriate during periods of start-up, shutdown and malfunction.

If EPA insists on setting emission limits for these periods of operation then the Agency must obtain emission data during these periods of operation and properly analyze those data in order to set MACT emission limits.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Richard L. Killion
Commenter Affiliation: Babcock and Wilcox Power Generation Group
Document Control Number: EPA-HQ-OAR-2002-0058-2722.1
Comment Excerpt Number: 12

Comment: Under the proposed rules, particulate matter would need to be continuously monitored. The EPA CEMS data does not indicate whether SSM conditions were present. Therefore, the validity of that data for determining the impact of SSM conditions is unknown. B&W recommends that the units that set the floor limits should be continuously monitored and tested during SSM conditions to verify the ability to meet a 30-day rolling average with SSM.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: American Crystal Sugar Company and Michigan Sugar Company
Commenter Affiliation: Patricia Hansen and Steven Smock
Document Control Number: EPA-HQ-OAR-2002-0058-2970.1
Comment Excerpt Number: 12

Comment: Based on the EPA's 2008 Combustion Survey there are 13,555 boilers/process heaters currently in operation at major sources in the United States. To evaluate continuous operation, EPA used CEMS data from only six (6) existing boilers, which is not sufficient to fully evaluate variable load considerations as well as startup, shutdown and malfunction concerns for continuous compliance for all source categories. This amounts to an evaluation of 0.04 percent of the sources to provide a representative limit for all sources.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Gary Melow
Commenter Affiliation: Michigan Biomass
Document Control Number: EPA-HQ-OAR-2002-0058-2776.1
Comment Excerpt Number: 12

Comment: See submittal for Attachment A is a table that demonstrates this phenomenon with an arbitrary CO level of 20 PPM raw under various O2 conditions.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: A. Steven Young
Commenter Affiliation: Association of Independent Corrugated Converters
Document Control Number: EPA-HQ-OAR-2002-0058-2899.1
Comment Excerpt Number: 12

Comment: EPA's analysis failed to properly address the variability of the data, as well as emissions associated with startup, shutdown and malfunction. Thus, EPA's proposed limits do not appropriately address the variability in emissions of various HAPs.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Scott Manley
Commenter Affiliation: Wisconsin Manufacturers and Commerce
Document Control Number: EPA-HQ-OAR-2002-0058-2933.1
Comment Excerpt Number: 12

Comment: Finally, EPA's analysis failed to properly address the variability of the data, as well as emissions associated with startup, shutdown and malfunction. Thus, EPA's proposed limits do not appropriately address the variability in emissions of various HAPs. In addition, EPA's proposed limits are unduly impacted by issues associated with the limits of detection. Fundamentally, numerical limits should be based on quantifiable and reproducible test results consistent with reliable source test methods that have well-established performance. Limits should not be based on tests and methods that raise issues of significant measurement and other uncertainties.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Richard Krock
Commenter Affiliation: The Vinyl Institute
Document Control Number: EPA-HQ-OAR-2002-0058-2944.1
Comment Excerpt Number: 13

Comment: EPA's approach to addressing startup, shutdown, and malfunction (SSM) periods in the Proposed Boiler MACT is contrary to the statute's requirement that the standards established under section 112(d) be "achievable." See 42 U.S.C. § 7412(d)(2). Furthermore, EPA's claims that the MACT standards reflect startup and shutdown periods are not supported by the record. EPA needs to identify test data submissions that were performed during SSM and assess whether enough data exists to demonstrate that emissions during SSM are accounted for and are achievable. EPA should also set work practice standards for SSM events, since EPA did not correctly consider emissions from SSM events.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Sarah E. Amick
Commenter Affiliation: Rubber Manufacturers Association
Document Control Number: EPA-HQ-OAR-2002-0058-2941.1
Comment Excerpt Number: 13

Comment: EPA makes a mistake with regard to its proposal not to set a separate standard for periods of startup, shutdown, and malfunction. On the one hand, EPA asserts that "[t]he standards we are proposing are daily or monthly averages ... [t]hus, we are not establishing separate emission standards for these periods because startup and shutdown are part of their routine operations and, therefore, are already addressed by the standards." On the other hand, EPA uses short term performance test results to set the standards rather than the results of long-term CEMS monitoring. As a result, the emissions data on which the standards are based do not, in fact, reflect or adequately accommodate emissions from periods of startup, shutdown, or malfunction.

To assure that startup, shutdown, and malfunction are appropriately accommodated, EPA must either assure that the data on which the standard is based include representative data from such periods or, alternatively, set a separate work practice standard to properly accommodate startup, shutdown, and malfunction.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Bill Wemhoff
Commenter Affiliation: National Rural Electric Cooperative Association
Document Control Number: EPA-HQ-OAR-2002-0058-2835.1
Comment Excerpt Number: 13

Comment: Concerned about the potential for enforcement of operating parameter and opacity limits during periods of startup, shutdown, and in the event of equipment malfunction. When EPA finalized its rule in 2004 with enforceable operating parameters, it did so with a rule that also made clear that those limits did not apply during periods of "startup, shutdown, and malfunction." 40 C.F.R. § 63.7505(a), 69 Fed. Reg. at 55,254. EPA's current proposal contains no such exception, but instead would allow enforcement of deviations from operating parameters during these periods, when controls would not be expected to be operating at the same levels as during performance tests, and due solely to equipment malfunctions. In its proposed rule, EPA asserts that it has taken startup and shutdown periods into account by using continuous emissions monitoring system ("GEMS") data from best performing units that include periods of startup and shutdown, and by proposing use of "daily or monthly averages." Regarding malfunctions, EPA asserts that it would use a variety of information to determine an appropriate response to exceedance caused by equipment malfunction.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Richard L. Killion
Commenter Affiliation: Babcock and Wilcox Power Generation Group
Document Control Number: EPA-HQ-OAR-2002-0058-2722.1
Comment Excerpt Number: 13

Comment: Exemption following new unit and major maintenance overhaul starts

There needs to be an exemption in the rule for each SSM period associated with commissioning of new units and with a restart following a major maintenance overhaul of the unit. Emissions will be higher during these periods while equipment and controls are brought into service for the first time. This is part of new/overhauled equipment commissioning and needs to be recognized by the compliance limits.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Gary Melow
Commenter Affiliation: Michigan Biomass
Document Control Number: EPA-HQ-OAR-2002-0058-2776.1
Comment Excerpt Number: 13

Comment: While this issue may be "hidden" for compounds that are stack tested (assuming stack tests never occur during startup or shutdown), this issue is very obvious for pollutants that are continuously monitored. Even with a 30-day averaging period, the monthly CO average PPM values would be affected by including startup and shutdown events on a PPM corrected basis.

Additionally, we have a concern that if a standard includes startup and shutdown events, an agency could require stack testing during startup and shutdown events to ensure compliance under worst-case operating conditions.

Response: See the preamble for response to how EPA adjusted CO emission limits and compliance mechanisms, and changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Steven G. Hanson
Commenter Affiliation: Graphic Packaging International
Document Control Number: EPA-HQ-OAR-2002-0058-2723.1
Comment Excerpt Number: 14

Comment: EPA has not appropriately accounted for startup and shutdown emissions. While EPA makes the simplistic statement that boilers do not normally startup and shutdown more than once per day, they have not accounted for the fact that the startup and shutdown process is not like turning a light switch on and off — such processes on boilers can take several hours, with safety being a predominant concern in the practices employed.

1. Control devices may not be capable of normal operation during periods of startup and shutdown, meaning monitored parameters would not be within ranges established during performance testing.

2. Ranges established during performance testing for parametric monitors are based on maximum normal operations, which differ substantially from startup and shutdown processes.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Bill Wemhoff
Commenter Affiliation: National Rural Electric Cooperative Association
Document Control Number: EPA-HQ-OAR-2002-0058-2835.1
Comment Excerpt Number: 14

Comment: NREGA believes EPA's assertions regarding startup and shutdown are inapplicable to control device operating parameter limits, which are based on 12-hour averages (not daily or monthly averages) established during performance test (not based on GEMS data that include startup and shutdown). Even a daily block average, as proposed for opacity, does not provide sufficient protection if the unit does not startup or shutdown at exactly midnight, since there might not be sufficient data under normal operating conditions to compensate for the startup or shutdown period. In short, believes EPA has not made sufficient allowance in its rules for periods of startup and shutdown. To the contrary, 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," and then maintain those levels during periods other than maximum normal operating load, including startup and shutdown. Thinks EPA's proposal is unreasonable and the agency must address these periods by allowing sources to identify alternative parameters or by establishing simple work practice standards for these periods.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Robert Thornton
Commenter Affiliation: International District Energy Association
Document Control Number: EPA-HQ-OAR-2002-0058-2918.1
Comment Excerpt Number: 15

Comment: The proposed rule fails to adequately account for variability in emissions resulting from unavoidable variations in loads and fuel mix and due to start-up, shutdown and malfunction (SSM).

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Sarah E. Amick
Commenter Affiliation: Rubber Manufacturers Association
Document Control Number: EPA-HQ-OAR-2002-0058-2941.1
Comment Excerpt Number: 40

Comment: EPA's approach to addressing SSM periods in the Proposed Boiler MACT is contrary to the statute's requirement that the standards established under section 112(d) be "achievable." See 42 U.S.C. § 7412(d)(2). Furthermore, EPA's claims that the MACT standards reflect startup and shutdown periods are not supported by the record.

To address the decision in Sierra Club v. EPA, 551 F.3d 1019 (D.C. Cir. 2008), cert. denied, 2010 U.S. LEXIS 2265(2010), which vacated the exemption in 40 C.F.R. § 63.6(f)(1) and (h)(1) for SSM periods, EPA proposes emissions standards in the MACT for industrial boilers and process heaters that apply at all times, including periods of SSM. EPA claims in the preamble that startup and shutdown periods were taken into consideration when setting the MACT standards. See Proposed Boiler MACT Rule at 32,012-13. According to the preamble, continuous emissions monitoring data from the best performing units, which include startup and shutdown periods, are used to set the floor levels in the proposed rule. See id. at 32,013. EPA further notes that startup and shutdown are part of "routine operations" and are therefore "already addressed" in the MACT standards. See id.

With regard to malfunctions, however, EPA states that these periods should not be viewed as a "distinct operating mode," and thus, emissions from these periods do not need to be factored into developing the MACT floor levels. See id. Moreover, EPA states that even if malfunctions were to be considered a distinct operating mode, it would be "impracticable to take malfunctions into account in setting CAA section 112(d) standards for major source boilers and process heaters"

given that these episodes are by definition sudden and unexpected events which vary in degree, frequency, and duration. Id.
When setting standards in the early 1990's under CAA 112(d), EPA used its New Source Performance Standards (NSPS) program as a model. The section 112 standards were acknowledged by EPA to be "essentially equivalent to [section 111] performance standards" and that "unpredicted and reasonably unavoidable failures of air pollution control systems" would occur. 58 Fed.Reg. 42,760, 42,777 (Aug. 11, 1993). To address this situation, EPA adopted a similar exemption to the one in the NSPS Program for SSM events and imposed a "general duty" to minimize emissions. Thus, EPA acknowledged, as early as 1993, that SSM events are not appropriate for inclusion in a MACT standard and that an alternative approach should be used to address these situations. While the D.C. Circuit has ruled that sources cannot be exempt from complying with MACT standards, the court noted that Congress recognized in some instances that it may not be feasible to prescribe or enforce an emission standard under section 112, and so section 112(h) "work practices" or "operational" standards are available in certain limited situations. See Sierra Club v. EPA, 551 F.3d at 1028.

The D.C. Circuit also has recognized that standards based on what sources achieve must account for the limitations inherent in the technology used to reduce emissions. For example, in a case reviewing NSPS under section 111 of the CAA, Portland Cement Ass'n v. Ruckelshaus, 486 F.2d 375, 398 (D.C. Cir. 1973), the court acknowledged that "'startup' and 'upset' conditions due to plant or emission device malfunction, is an inescapable aspect of industrial life and that allowance must be made for such factors in the standards that are promulgated." Id. at 399. Furthermore, in National Lime Ass'n v. EPA, 627 F.2d 416 (D.C. Cir. 1980), the court noted that "a uniform standard must be capable of being met under most adverse conditions which can reasonably be expected to recur." Id. at 431 n.46. The D.C. Circuit acknowledged this same principle almost 20 years later when reviewing emission standards for new sources in the medical waste incinerator rule under section 129 in Sierra Club v. EPA, 167 F.3d 658 (D.C. Cir. 1999). In that case, while the court did not find the record sufficient to support EPA's approach for new sources, the D.C. Circuit did not object to a standard-setting approach which would account for the performance of technology under the "worst reasonably foreseeable circumstances." See id. at 665. Furthermore, the D.C. Circuit reiterated the principle in National Lime that "where a statute requires that a standard be 'achievable,' it must be achievable 'under the most adverse circumstances which can reasonably be expected to recur.'" Id. at 665 (citing National Lime Ass'n v. EPA, 627 F.2d 416, 431 n.46 (D.C. Cir. 1980)).

EPA's MACT floor-setting approach in the Proposed Boiler MACT ignores these longstanding principles and mischaracterizes the role startup and shutdown data plays (or rather, does not play, as the case is here) in EPA's floor-setting process. As noted above, EPA claims that the agency considered startup and shutdown periods when setting the floors because CEMS data, relied on by EPA in "establishing the standards," included data from those periods. See Proposed Boiler MACT Rule at 32,012. Despite this claim, however, EPA does not rely on the CEMs data when setting the floors for boilers and process heaters. To the contrary, as indicated by the ERG memorandum in the docket, EPA uses test run data collected through the ICR phase II testing process, which reflect normal (often steady state) operating conditions, to set the proposed floors. See Memorandum from A. Singelton, ERG, to J. Eddinger, U.S. EPA, MACT Floor Analysis (2010) for the Industrial, Commercial, and Institutional Boilers and Process Heaters National

Emission Standards for Hazardous Air Pollutants – Major Source at 3 (April 2010). Thus, according to EPA's own docket materials, the data used to set the proposed floors fail to account for the dynamic conditions and variable emissions occurring during startup and shutdown episodes. Furthermore, as the ERG memorandum makes abundantly clear, EPA's approach does not make use of the CEMs data (with the startup and shutdown information) in its variability analysis where it would be the most helpful in reflecting real world fluctuations in emissions. Id. Given the absence of startup and shutdown emissions information from the test run data relied on by EPA to set the proposed standards and the difficulty of collecting data from such brief operation periods, it is appropriate for EPA to set work practices for these events for boilers and process heaters. As noted earlier, section 112(h) allows EPA to set work practice standards for situations where "it is not feasible in the judgment of the Administrator to prescribe or enforce an emission standard . . . ." CAA § 112(h)(1); 42 U.S.C. § 7412(h)(1). Gathering data from startup and shutdown periods would be challenging given the brief nature of these periods as well as the need to define the exact time period for what is considered "startup" and/or "shutdown." Moreover, the definition of "not feasible to prescribe or enforce an emission standard" is defined in the CAA as any situation where "the application of measurement methodology to a particular class of sources is not practicable due to technological and economic limitations." CAA § 112(h)(2); 42 U.S.C. § 7412(h)(2). Startup and shutdown episodes fit with this definition and would justify the agency setting work practices to address emissions during these periods. Furthermore, a work practices approach for these periods would be in keeping with the statute's requirement that MACT standards be "achievable" as well as with the requirement that a MACT standard apply at all times.

A work practices approach for these periods also would be consistent with EPA's recently promulgated MACT standards for compression ignition reciprocating internal combustion engines (CI-RICE). See National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines, Final Rule, 75 Fed.Reg. 9648 (Mar. 3, 2010). Based on comments received from stakeholders, EPA finalized work practice standards for startup because the agency determined that it was "not feasible to finalize numerical emission standards that would apply during startup because the application of measurement methodology to this operation is not practicable due to technological and economic limitations." Id. at 9656. According to EPA, applicable test methods that would be needed to measure during these events "do not respond adequately to the relatively short term and highly variable exhaust gas characteristics occurring during these periods." Id. at 9665. Furthermore, EPA determined that the cost for testing all the engines affected by the rule to get the necessary data could be more than $1 billion. See id. Startup and shutdown periods for boilers encounter similar testing challenges and costs.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Lee B. Zeugin
Commenter Affiliation: Utility Air Regulatory Group
Document Control Number: EPA-HQ-OAR-2002-0058-2880.1

Comment Excerpt Number: 40

Comment: EPA's preamble assertions regarding startup and shutdown are inapplicable to control device operating parameter limits, which are based on 12-hour averages (not daily or monthly averages) established during performance test (not based on CEMS data that include startup and shutdown). Even a daily block average, as proposed for opacity, does not provide sufficient protection if the unit does not startup or shutdown at exactly midnight, since there might not be sufficient data under normal operating conditions to compensate for the startup or shutdown period. In short, EPA has made absolutely no allowance in its rules for periods of startup and shutdown. To the contrary, 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," and then maintain those levels during periods other than maximum normal operating load, including startup and shutdown. EPA's proposal is patently unreasonable. EPA must address these periods in some other manner, for example by establishing simple work practice standards in lieu of operating parameters.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Sarah E. Amick
Commenter Affiliation: Rubber Manufacturers Association
Document Control Number: EPA-HQ-OAR-2002-0058-2941.1
Comment Excerpt Number: 41

Comment: With respect to malfunctions, as noted earlier, EPA argues in the preamble to the Proposed Boiler MACT that these periods should not be considered a "distinct operating mode" and uses this to justify not factoring these emissions into the proposed MACT standards. Considering that EPA's proposed MACT standards are supposed to apply at all times, the implication is that periods of malfunction also are covered by the MACT standards that apply during normal operations. This directly conflicts with the statutory requirement that the MACT standard be "achievable."

Given that the floor data does not consider malfunctions and that the statute requires that the MACT standard be "achievable," EPA should set work practice requirements to address periods of malfunctions as well. As noted above, section 112(h) allows EPA to set work practice standards for situations where "it is not feasible in the judgment of the Administrator to prescribe or enforce an emission standard . . . ." Similar to startup and shutdown, malfunctions fit with the situations described in the definition of "not feasible to prescribe or enforce an emission standard" as any situation where "the application of measurement methodology to a particular class of sources is not practicable due to technological and economic limitations." Emission testing for malfunctions would be near impossible to conduct given the sporadic and unpredictable nature of the events. As noted earlier, EPA acknowledges in the preamble to the Proposed Boiler Rule that it is "impracticable" to take periods of malfunctions into account when setting emissions standards given the "myriad different types of malfunctions that can occur across all sources in the category" and that "malfunctions can vary in frequency, degree, and duration, further complicating" the standard setting process. 75 Fed.Reg. at 32,013. Section 112(h) work practice standards, therefore, are well-suited to address malfunction periods and the complexities and challenges surrounding collecting data and establishing numerical standards for those events.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Lee B. Zeugin
Commenter Affiliation: Utility Air Regulatory Group
Document Control Number: EPA-HQ-OAR-2002-0058-2880.1
Comment Excerpt Number: 41

Comment: EPA's promise to address periods of equipment malfunction by considering other information before enforcing exceedances of operating limits also provide little comfort, especially given the risk of citizen suits. Although UARG appreciates EPA's proposal to make clear that "deviations" of operating limits are not necessarily violations, nothing in EPA's proposal would prevent EPA, a state, or a plaintiff in a citizen suit from simply determining in their "discretion" that any particular exceedance constitutes a violation. Proposed § 63.7575. MACT standards are technology-based standards and must recognize that even the best performing technology occasionally fails.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Kevin M. Dempsey
Commenter Affiliation: American Iron and Steel Institute
Document Control Number: EPA-HQ-OAR-2002-0058-2998.1
Comment Excerpt Number: 42

Comment: If EPA Adopts Numeric Emissions Limitations, the Final Rule Must Include a Separate Standard for Periods of Startup and Shutdown

The Proposed Rule does not include a separate standard for startup and shutdown. This is a fundamental problem that, if not corrected, will cause the final standards to be unachievable by even well designed and operated boilers. As a result, EPA must include a separate standard for startup and shutdown in the final rule.

EPA's emissions database provides continuous emissions monitoring system (CEMS) data from several of the better performing sources. Contrary to EPA's assertion in the preamble, these data show that daily average emissions should be expected to vary considerably on a day-to-day basis and that the variability spans the proposed levels of the standards. While it is difficult to discern the reasons for this variability based on the information provided in the database, there is little doubt that startups and shutdowns significantly contribute to the variable emissions performance of these units. Thus, the data indicate that EPA needs to include express accommodation for startups and shutdowns.

Second, basic scientific and engineering principles support the need for a separate standard for startup and shutdown. Particularly for CO emissions, combustion conditions will not be optimum during startup periods due to the generally low firing rate and the fact that the firing rate will be ramped up over the startup period. Thus, a significant period of non-optimum firing conditions will result in CO emissions performance – even on a daily average basis – that will be markedly different than performance during normal operations. EPA’s failure to acknowledge these basic technical and engineering principles renders the proposed standards arbitrary.

For these reasons, we believe that a separate standard for startup and shutdown is needed and is amply justified. We suggest that a work practice standard is most appropriate due to the lack of relevant data and the fact that an emission testing during startup is not technically and economically practicable. If EPA decides that a numeric standard is needed, the Agency should rely on the available long term data from the better performing boilers to establish a standard with a reasonably long averaging time (such as a 30-day rolling average), rather than the proposed 24-hour averaging time.

Response: See the preamble for response to how EPA adjusted CO emission limits and compliance mechanisms, and changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Lee B. Zeugin
Commenter Affiliation: Utility Air Regulatory Group
Document Control Number: EPA-HQ-OAR-2002-0058-2880.1
Comment Excerpt Number: 53

Comment: EPA has failed to consider the limitations of PM CEMS in measuring emissions during periods of startup, shutdown, and malfunction, which are not conditions under which the PM CEMS are correlated.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Lee B. Zeugin
Commenter Affiliation: Utility Air Regulatory Group
Document Control Number: EPA-HQ-OAR-2002-0058-2880.1
Comment Excerpt Number: 57

Comment: Because EPA's proposed standard provides no exception for periods of startup, shutdown, or malfunction, the standard must be achievable under those conditions as well as the normal operating conditions under which stack tests are conducted. According to EPA's preamble discussion, EPA intends to address startup and shutdown by using daily or monthly averages and by establishing standards using CEMS data that include periods of startup and shutdown. 75 Fed. Reg. at 32,013. Again, since EPA has not identified any PM CEMS data used to establish the proposed standards, let alone PM CEMS data that include periods of startup and shutdown, UARG assumes that EPA intends to rely solely on averaging time to compensate for the higher emission rates expected during those periods. However, EPA has no basis to assume that PM CEMS data collected during periods of startup and shutdown will be accurate even within the permissible error bands described above, because PM CEMS are not correlated to Method 5 under those conditions (nor could they be given the difficulty of performing EPA test methods under such non-steady state conditions).

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Alicia Oman
Commenter Affiliation: National Association of Manufacturers
Document Control Number: EPA-HQ-OAR-2002-0058-2845.1
Comment Excerpt Number: 62

Comment: In addition, during Start-up, Shutdown, Malfunction (SSM) periods, boilers and process heaters operate under conditions that are likely to generate unavoidable increases in CO emissions. These conditions are driven by safety considerations (e.g., ensuring sufficient air flow to avoid explosive fuel-rich scenarios), operational concerns (e.g., gradually warming up the equipment in order to prevent thermal damage), and warranty requirements (e.g., equipment vendors require gradual warm-up as a warranty condition). Thus, setting the proposed inappropriately low CO emissions limit will encourage quick start-up and shutdown of equipment in order avoid exceedances of limit. EPA should not promulgate a rule that promotes such unsafe and improper operation of boilers and process heaters.

Response: See the preamble for response to how EPA adjusted CO emission limits and compliance mechanisms, and changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Alicia Oman
Commenter Affiliation: National Association of Manufacturers
Document Control Number: EPA-HQ-OAR-2002-0058-2845.1
Comment Excerpt Number: 63

Comment: EPA's approach to addressing startup, shutdown, and malfunction (SSM) periods in the Proposed Boiler MACT is contrary to the statute's requirement that the standards established under section 112(d) be "achievable." See 42 U.S.C. § 7412(d)(2). Furthermore, EPA's claims that the MACT standards reflect startup and shutdown periods are not supported by the record.

To address the decision in Sierra Club v. EPA, 551 F.3d 1019 (D.C. Cir. 2008), cert. denied, 2010 U.S. LEXIS 2265(2010), which vacated the exemption in 40 C.F.R. § 63.6(f)(1) and (h)(1) for SSM periods, EPA proposes emissions standards in the MACT for industrial boilers and process heaters that apply at all times, including periods of SSM. EPA claims in the preamble that startup and shutdown periods were taken into consideration when setting the MACT standards. See Proposed Boiler MACT Rule at 32,012-13. According to the preamble, continuous emissions monitoring data from the best performing units, which include startup and shutdown periods, are used to set the floor levels in the proposed rule. See id. at 32,013. EPA further notes that startup and shutdown are part of "routine operations" and are therefore "already addressed" in the MACT standards. See id.

With regard to malfunctions, however, EPA states that these periods should not be viewed as a "distinct operating mode," and thus, emissions from these periods do not need to be factored into developing the MACT floor levels. See id. Moreover, EPA states that even if malfunctions were to be considered a distinct operating mode, it would be "impracticable to take malfunctions into account in setting CAA section 112(d) standards for major source boilers and process heaters" given that these episodes are by definition sudden and unexpected events which vary in degree, frequency, and duration. Id.

When setting standards in the early 1990's under CAA 112(d), EPA used its New Source Performance Standards (NSPS) program as a model. The section 112 standards were acknowledged by EPA to be "essentially equivalent to [section 111] performance standards" and that "unpredicted and reasonably unavoidable failures of air pollution control systems" would occur. 58 Fed. Reg. 42,760, 42,777 (Aug. 11, 1993). To address this situation, EPA adopted a similar exemption to the one in the NSPS Program for SSM events and imposed a "general duty" to minimize emissions. Thus, EPA acknowledged, as early as 1993, that SSM events are not appropriate for inclusion in a MACT standard and that an alternative approach should be used to address these situations. While the D.C. Circuit has ruled that sources cannot be exempt from complying with MACT standards, the court noted that Congress recognized in some instances that it may not be feasible to prescribe or enforce an emission standard under section 112, and so section 112(h) "work practices" or "operational" standards are available in certain limited situations. See Sierra Club v. EPA, 551 F.3d at 1028.

The D.C. Circuit also has recognized that standards based on what sources achieve must account for the limitations inherent in the technology used to reduce emissions. For example, in a case reviewing NSPS under section 111 of the CAA, Portland Cement Ass'n v. Ruckelshaus, 486 F.2d 375, 398 (D.C. Cir. 1973), the court acknowledged that "'startup' and 'upset' conditions due to plant or emission device malfunction, is an inescapable aspect of industrial life and that allowance must be made for such factors in the standards that are promulgated." Id. at 399. Furthermore, in National Lime Ass'n v. EPA, 627 F.2d 416 (D.C. Cir. 1980), the court noted that "a uniform standard must be capable of being met under most adverse conditions which can reasonably be expected to recur." Id. at 431 n.46. The D.C. Circuit acknowledged this same principle almost 20 years later when reviewing emission standards for new sources in the medical waste incinerator rule under section 129 in Sierra Club v. EPA, 167 F.3d 658 (D.C. Cir. 1999). In that case, while the court did not find the record sufficient to support EPA's approach for new sources, the D.C. Circuit did not object to a standard-setting approach which would account for the performance of technology under the "worst reasonably foreseeable circumstances." See id. at 665. Furthermore, the D.C. Circuit reiterated the principle in National Lime that "where a statute requires that a standard be 'achievable,' it must be achievable 'under the most adverse circumstances which can reasonably be expected to recur.'" Id. at 665 (citing National Lime Ass'n v. EPA, 627 F.2d 416, 431 n.46 (D.C. Cir. 1980)).

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Alicia Oman
Commenter Affiliation: National Association of Manufacturers
Document Control Number: EPA-HQ-OAR-2002-0058-2845.1
Comment Excerpt Number: 64

Comment: EPA's MACT floor-setting approach in the Proposed Boiler MACT ignores these longstanding principles and mischaracterizes the role startup and shutdown data plays (or rather, does not play, as the case is here) in EPA's floor-setting process. As noted above, EPA claims that the agency considered startup and shutdown periods when setting the floors because CEMS data, relied on by EPA in "establishing the standards," included data from those periods. See Proposed Boiler MACT Rule at 32,012. This representation is a serious misstatement of the Agency's record. EPA does not rely on the CEMs data when setting the floors for boilers and process heaters. To the contrary, as indicated by the ERG memorandum in the docket, EPA uses test run data collected through the ICR phase II testing process, which reflect normal (often steady state) operating conditions, to set the proposed floors. See Memorandum from A. Singelton, ERG, to J. Eddinger, U.S. EPA, MACT Floor Analysis (2010) for the Industrial, Commercial, and Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants – Major Source at 3 (April 2010). Thus, according to EPA's own docket materials, the data used to set the proposed floors fail to account for the dynamic conditions and variable emissions occurring during startup and shutdown episodes. Furthermore, as the ERG memorandum makes abundantly clear, EPA's approach does not make use of the CEMs data (with the startup and shutdown information) in its variability analysis where it would be the most helpful in reflecting real world fluctuations in emissions. Id.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Alicia Oman

Commenter Affiliation: National Association of Manufacturers
Document Control Number: EPA-HQ-OAR-2002-0058-2845.1
Comment Excerpt Number: 65

Comment: Given the absence of startup and shutdown emissions information from the test run data relied on by EPA to set the proposed standards and the difficulty of collecting data from such brief operation periods, it is appropriate for EPA to set work practices for these events for boilers and process heaters. As noted earlier, section 112(h) allows EPA to set work practice standards for situations where “it is not feasible in the judgment of the Administrator to prescribe or enforce an emission standard . . . .” CAA § 112(h)(1); 42 U.S.C. § 7412(h)(1). Gathering data from startup and shutdown periods would be challenging given the brief nature of these periods as well as the need to define the exact time period for what is considered “startup” and/or “shutdown.” Moreover, the definition of “not feasible to prescribe or enforce an emission standard” is defined in the CAA as any situation where “the application of measurement methodology to a particular class of sources is not practicable due to technological and economic limitations.” CAA § 112(h)(2); 42 U.S.C. § 7412(h)(2). Startup and shutdown episodes fit with this definition and would justify the agency setting work practices to address emissions during these periods. Furthermore, a work practices approach for these periods would be in keeping with the statute’s requirement that MACT standards be “achievable” as well as with the requirement that a MACT standard apply at all times.

A work practices approach for these periods also would be consistent with EPA’s recently promulgated MACT standards for compression ignition reciprocating internal combustion engines (CI-RICE). See National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines, Final Rule, 75 Fed. Reg. 9648 (Mar. 3, 2010). Based on comments received from stakeholders, EPA finalized work practice standards for startup because the agency determined that it was “not feasible to finalize numerical emission standards that would apply during startup because the application of measurement methodology to this operation is not practicable due to technological and economic limitations.” Id. at 9656. According to EPA, applicable test methods that would be needed to measure during these events “do not respond adequately to the relatively short term and highly variable exhaust gas characteristics occurring during these periods.” Id. at 9665. Furthermore, EPA determined that the cost for testing all the engines affected by the rule to get the necessary data could be more than $1 billion. See id. Startup and shutdown periods for boilers present similar levels of testing challenges and costs.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Alicia Oman
Commenter Affiliation: National Association of Manufacturers
Document Control Number: EPA-HQ-OAR-2002-0058-2845.1
Comment Excerpt Number: 66

Comment: Malfunctions, EPA argues in the preamble to the Proposed Boiler MACT that these periods should not be considered a "distinct operating mode" and uses this to justify not factoring these emissions into the proposed MACT standards. Considering that EPA's proposed MACT standards are supposed to apply at all times, the implication is that periods of malfunction also are covered by the MACT standards that apply during normal operations. This directly conflicts with the statutory requirement that the MACT standard be "achievable."

Given that the floor data does not consider malfunctions and that the statute requires that the MACT standard be "achievable," EPA should set work practice requirements to address periods of malfunctions as well. As noted above, section 112(h) allows EPA to set work practice standards for situations where "it is not feasible in the judgment of the Administrator to prescribe or enforce an emission standard . . . ." Similar to startup and shutdown, malfunctions fit with the situations described in the definition of "not feasible to prescribe or enforce an emission standard" as any situation where "the application of measurement methodology to a particular class of sources is not practicable due to technological and economic limitations." Emission testing for malfunctions would be near impossible to conduct given the sporadic and unpredictable nature of the events. As noted earlier, EPA acknowledges in the preamble to the Proposed Boiler Rule that it is "impracticable" to take periods of malfunctions into account when setting emissions standards given the "myriad different types of malfunctions that can occur across all sources in the category" and that "malfunctions can vary in frequency, degree, and duration, further complicating" the standard setting process. Proposed Boiler MACT Rule at 32,013. Section 112(h) work practice standards, therefore, are well-suited to address malfunction periods and the complexities and challenges surrounding collecting data and establishing numerical standards for those events.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Lee B. Zeugin
Commenter Affiliation: Utility Air Regulatory Group
Document Control Number: EPA-HQ-OAR-2002-0058-2880.1
Comment Excerpt Number: 92

Comment: EPA's underlying database contains no data for start-up, shutdown or malfunction events — yet these periods of operation are not excluded from compliance obligations. This is yet another example of how the Agency has failed to show that the proposed emission limits are achievable. Another critical issue with respect to the achievability of the proposed emission limits is the absence of an exemption for start-up, shutdown and malfunction events. Clearly, the data upon which EPA characterized the best performing similar source and the best performing 12 percent of existing sources contain no start-up, shutdown or malfunction events. EPA has absolutely no technical basis to claim the proposed emission limits are achievable -- as is required by law.[42 U.S.C. §7412(d)(1).] If EPA insists on not exempting start-up, shutdown and malfunction events, the Agency must deal with emissions that occur during such events.

The simplest approach is to suggest that EPA obtain data representative of start-up, shutdown and malfunction events, include such data in a proper analysis and choose a numerical emission limits that can be achieved in practice. However, the data collection approach may not be realistic in every case. For example, manual test methods, such as EPA Method 5 for PM, are designed to be used under steady state conditions. Trying to conduct a Method 5 test during a boiler start-up may neither be practical nor accurate. Likewise, PM CEMS may not be the answer because a PM CEMS must be correlated with manual test data to be accurate. Thus, in cases where data collection during start-up, shutdown and malfunction events is not feasible, EPA should set work practice standards. However, EPA cannot simply ignore emission variability during start-up, shutdown and malfunction events and pretend that the emission limits are achievable without addressing this fundamental issue.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 97

Comment: EPA SHOULD DEVELOP STARTUP, SHUTDOWN, AND MALFUNCTION STANDARDS. ACC is very concerned about the lack of separate start-up, shutdown, and malfunction (SSM) emission standards or work practice standards within the proposed rule. EPA indicates in the preamble that it considered these periods in establishing the proposed standards. The following reasons are cited for not including such periods.

EPA's approach to SSM periods in this proposal is contrary to the statute's requirement that the standards established under section 112(d)(2) be "achievable." Furthermore, EPA's claims that the proposed standards reflect consideration of emissions during startup and shutdown periods are not supported by the record.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 98

Comment: To address the decision in Sierra Club v. EPA [551 F.3d 1019 (D.C. Cir. 2008), cert. denied, 2010 U.S. LEXIS 2265(2010).], which vacated the exemption in 40 C.F.R. section 63.6(f)(1) and (h)(1) for SSM periods, EPA proposes emissions standards in this rule that apply at all times, including periods of SSM. As noted above, EPA claims that startup and shutdown periods were taken into consideration when setting the MACT standards and that CEMS data from the best performing units, which include startup and shutdown periods, was used to set the floor levels in the proposed rule. EPA further notes that startup and shutdown are part of "routine operations" and are therefore "already addressed" in the standards. .

When setting standards in the early 1990's under section 112(d), EPA used its NSPS program as a model. The section 112 standards were acknowledged by EPA to be "essentially equivalent to [section 111] performance standards" and that "unpredicted and reasonably unavoidable failures of air pollution control systems" would occur. [58 Fed. Reg. 42760, 42777 (Aug. 11, 1993).] To address this situation, EPA adopted a similar exemption to the one in the NSPS Program for SSM events and imposed an overarching "general duty" to minimize emissions. Thus, EPA acknowledged, as early as 1993, that SSM events are not appropriate for inclusion in a MACT standard and that an alternative approach should be used to address these situations. While the D.C. Circuit has ruled that sources cannot be exempt from complying with MACT standards, the court noted that Congress recognized in some instances that it may not be feasible to prescribe or enforce an emission standard under section 112, and so section 112(h) "work practices" or "operational" standards are available in certain limited situations.[See Sierra Club v. EPA, 551 F.3d at 1028.]

The D.C. Circuit also has recognized that standards based on what sources achieve must account for the limitations inherent in the technology used to reduce emissions. For example, in a case reviewing performance standards under section 111 of the CAA,[Portland Cement Ass"n v. Ruckelshaus, 486 F.2d 375, 398 (D.C. Cir. 1973).] the court acknowledged that "'startup" and "upset" conditions due to plant or emission device malfunction, is an inescapable aspect of industrial life and that allowance must be made for such factors in the standards that are promulgated."[Id at 399.] Furthermore, in National Lime Ass"n v. EPA, [627 F.2d 416 (D.C. Cir. 1980).] the court noted that "a uniform standard must be capable of being met under most adverse conditions which can reasonably be expected to recur." [Id at 431 n.46.] The D.C. Circuit acknowledged this same principle almost twenty years later when reviewing emission standards for new sources in the medical waste incinerator rule under CAA section 129. [Sierra Club v EPA, 167 F.3d 658 (D.C. Cir. 1999).] In that case, while the court did not find the record sufficient to support EPA's approach for new sources, the D.C. Circuit did not object to a standard-setting approach which would account for the performance of technology under the "worst reasonably foreseeable circumstances."[Id at 665.] Furthermore, the D.C. Circuit reiterated the principle in Ntil Li that "where a statute requires that a standard be "achievable," it must be achievable "under the most adverse circumstances which can reasonably be expected to recur.""[Id at 665 (citing National Lime Ass"n v. EPA, 627 F.2d 416, 431 n.46 (D.C. Cir. 1980)).]

EPA's MACT floor-setting approach in this proposed rule ignores these longstanding principles and mischaracterizes the role startup and shutdown data plays (or rather, does t play, as the case is here) in EPA's floor-setting process. As noted above, EPA claims that it considered startup and shutdown periods when setting the floors because CEMS data, relied on by EPA in "establishing the standards," included data from those periods. However, EPA does not rely on the CEMS data when setting the floors for boilers and process heaters. To the contrary, as shown in the floor memo, EPA uses test run data collected through the Phase II ICR testing process, which reflect normal (often steady state) operating conditions, to set the proposed floors. Thus, according to EPA's own docket materials, the data used to set the proposed floors fail to account for the dynamic conditions and variable emissions occurring during startup and shutdown episodes. Furthermore, as the floor memo makes abundantly clear, EPA's approach does not make use of the CEMS data (with the startup and shutdown information) in its variability analysis where it would be the most helpful in reflecting real world fluctuations in emissions.[EPA-HQ-OAR-2002-0058-0815].

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 99

Comment: The data shown below [see submittal for Figure 8 and Figure 9] is a subset of the data in the docket. These excerpts reflect start-up and shutdown CO data from two facilities: a coal fired unit and a wood fired unit. Both data sets provide EPA data during periods of start-up and shutdown. While the absolute values are different in both cases, the data indicate that carbon monoxide levels are up to twenty times greater during such periods. This is due to the influence of oxygen levels, i.e., when fuel values are low, as during periods of start-up and shutdown, oxygen levels are higher, making the corrected pollutant concentrations much higher. Further, as noted in the data set, the raw pollutant levels are elevated due to unstable combustion.

If EPA had examined these data in some detail, it would have recognized two important aspects of the startup and shutdown periods. First, during startup periods, the oxygen content of the flue gas is generally very high, resulting in high calculated concentrations of pollutants, when they are corrected to 3 or 7 percent oxygen. Second, during shutdown periods, solid fuel boilers continue to emit pollutants for some time while the fuel feed rate has gone to zero. Thus, during those periods the pollutant emission rates when measured in terms of the heat input rate would contain a zero in the denominator and would equal infinity. Combining emissions during shutdown periods with all operating periods would mean an emission limit of infinity. Based on this ridiculous outcome, we recommend that EPA exclude periods of startup and shutdown from its numerical standards and replace them with work practice standards aimed at minimizing pollutant emissions.

It is apparent that EPA did not consider this data when it established the proposed standards. In each of the cases presented above, the proposed standards would have been exceeded during a 30 day period based simply on a start-up and shutdown event. We believe that EPA should strongly reconsider this information before finalizing a standard that "considers" startup and shutdown events.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 100

Comment: Data is not available in the data sets provided by EPA, but the following hypothetical example demonstrates the effect. The methodology to be used to demonstrate compliance with the particulate limits would be as follows:

Equation 19-1 of 40 CFR 60 Appendix A Method 19:

$E = Cd * Fd * 20.9/(20.9 – O2d)$

Where

Cd = Pollutant Concentration (lb/dscf).
Fd = F Factor (dscf/MMBTU). Assume wood firing F = 9240 O2d = Oxygen Concentration (%).

Using the above equation the following set of results can be calculated: [see submittal for unnumbered table.]

In such situations it is very likely sources will exceed the proposed standards for several hours until combustion is stabilized. In this example, a start-up period of just a few hours would exceed the standard of 0.02 lb/MMBTU. Similar examples could be generated for the other pollutants regulated in the proposal, given adequate time to comment. It is important to note that in the above scenario, the actual concentration emitted is held constant. In real situations this may not be the case.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 101

Comment: Institutional, commercial and industrial boilers, like their larger Electric Generating Unit (EGU) analogs, require an extended period of startup during which most, if not all, equipment in the boiler and pollution control systems are not operating in their normal condition.

This extended startup period, typically several hours, is required due to equipment integrity concerns, limitations of the technologies, or safety concerns:

Equipment Integrity – A Fabric Filter (FF) cannot be put into service until the flue gas temperature is above the dew point. This requires that all heat transfer surfaces, ducts and flues from the combustion zone to the FF inlet be warmed up from ambient temperatures to dew point temperature (which varies by fuel type and fuel constituents, but is typically in excess of 140 degrees F / 60 degrees C and can be up to 280 degrees F/138 degrees C). It takes a considerable amount of time, typically several hours for larger units, to warm up this considerable mass of refractory and steel: waterwall tubes, superheater tubes, reheater tubes, economizer tubes, casings, turning vanes, air preheaters, ducts and inlet plenums. During this warm-up period, the FF cannot be put into service without risking catastrophic failure of the bags and intensive corrosion damage to the FF. Similarly, electrostatic precipitators (ESPs) must typically warm-up to be effective. Premature starting of this equipment will lead to short term stability problems that could result in unsafe actions and longer term degradation of ESP performance due to fouling, increased chances of wire damage or increased corrosion within the chambers. These situations limit a unit's ability to control Particulate Matter and Mercury during the several hours of startup.

Limitations of the Technology – Units equipped with a Spray Dryer Absorber (SDA) for acid gas removal are limited in the amount of reagent slurry that can be injected into the flue gas during startup. The slurry federate is limited due to the nature of the technology by the amount of moisture the flue gas can evaporate. This in turn requires that a minimum temperature be achieved by the flue gas before the slurry feed rate can be initiated, and imposes a lengthy period of time during which the slurry federate is significantly limited until all the upstream heat transfer surface and ductwork has been warmed up. As such, SDA cannot remove Hydrogen Chloride in significant quantities for several hours after the unit is first fired.

Safety Concerns – Reductions in the amount of time required to warm the boiler system up could be realized by increasing the ramp-rate of adding fuel to the unit. In theory, a boiler could be brought from first flame to full load in a matter of minutes, but decreasing the warm-up period from what the Original Equipment Manufacturer (OEM) recommends risks severe refractory damage and excessive metallurgical stresses due to rapid changes in temperature and wide variances in temperatures across boiler and duct parts. Immediate failures could occur if inconsistent heating caused tears or ruptures in support steel or heat transfer surfaces, posing considerable risk to personnel in the plant. Failure rates would also increase due to the considerable stresses introduced by rapid heating and cooling cycles, yielding failures at unpredictable times (steady state operation or future startups or shutdowns). For this reason, OEM recommendations for startup times are closely followed across industry.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Jim Griffin

Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 102

Comment: ACC applauds the fact that EPA is allowing the use of emissions averaging and common stack monitoring in its proposal, although ACC provides specific comments on how the emissions averaging provisions can be improved elsewhere in this document. However, in the context of periods of startup and shutdown, ACC does not see how either of these provisions would be particularly useful. For example, if a site has two boilers, one of which routinely achieves levels below the standard and one of which slightly above the standard, but averaged are able to achieve the required standard. It is unclear to ACC how these standards could be met during periods when the boiler with the lower emission rate is not operating.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 103

Comment: Given the limited carbon monoxide data and total absence of startup and shutdown emissions information for other pollutants from the test run data relied on by EPA to set the proposed standards and the infeasibility, if not impossibility, of collecting data from such brief operation periods for other pollutants, it is appropriate for EPA to set work practices for these events for boilers and process heaters. As noted earlier, section 112(h) allows EPA to set work practice standards for situations where it is not feasible to prescribe or enforce an emission standard. Gathering data for other pollutants from startup and shutdown periods would be nearly impossible given the brief nature of these periods, as well as the need to define the exact time period for what is considered ‘startup" and/or ‘shutdown,", and the fact that most reference methods would not perform well during these periods. Moreover, the definition of "not feasible to prescribe or enforce an emission standard" is defined in section 112(h) as any situation where "the application of measurement methodology to a particular class of sources is not practicable due to technological and economic limitations." Startup, shutdown, and malfunction events fit perfectly within this definition for the reasons outlined above and would justify EPA establishing work practices to address emissions during these periods. Furthermore, a work practices approach for these periods would be in keeping with the statute’s requirement that MACT standards be "achievable" as well as with the underlying requirement that a MACT standard apply at all times.

As discussed earlier in these comments, a work practices approach for these periods also would be consistent with EPA’s recently promulgated standards for CI-RICE. Based on comments received from stakeholders, EPA finalized work practice standards for startup because the Agency determined that it was "not feasible to finalize numerical emission standards that would apply during startup because the application of measurement methodology to this operation is not practicable due to technological and economic limitations."[RICE Rule, 75 Fed. Reg. at 9656.] According to EPA, applicable test methods that would be needed to measure during these events "do not respond adequately to the relatively short term and highly variable exhaust gas characteristics occurring during these periods."[Id. at 9665.] Furthermore, EPA determined that the cost for testing all the engines affected by the rule to get the necessary data could be more than $1 billion. [Id.] Startup and shutdown periods for boilers encounter similar testing challenges and costs.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 104

Comment: With regard to malfunctions, EPA states in this proposed rule that these periods should not be viewed as a "distinct operating mode," and thus, emissions from these periods do not need to be factored into developing the floor levels. Moreover, EPA states that even if malfunctions were to be considered a distinct operating mode, it would be "impracticable to take malfunctions into account in setting CAA section 112(d) standards for major source boilers and process heaters" given that these episodes are by definition sudden and unexpected events which vary in degree, frequency, and duration.

Considering that these proposed standards are supposed to apply at all times, during a malfunction the source would have to meet a standard established for emissions during normal operations. This directly conflicts with the statutory requirement that the MACT standard be "achievable." It also makes no sense for EPA to state that a malfunction is not a "distinct" operating mode but standards based on normal operating mode shall apply during a malfunction. Given that the floor data does not consider malfunctions and that the statute requires that the MACT standard be "achievable," EPA should establish work practice requirements to address periods of malfunctions as well. Emission testing for malfunctions would be near impossible to conduct given the sporadic and unpredictable nature of the events. EPA acknowledges in this proposed rule that it is "impracticable" to take periods of malfunctions into account when setting emissions standards given the "myriad different types of malfunctions that can occur across all sources in the category" and that "malfunctions can vary in frequency, degree, and duration, further complicating" the standard setting process.[75 Fed. Reg. at 32013.] Section 112(h) work practice standards, therefore, are well-suited to address malfunction periods and the complexities and challenges surrounding collecting data and establishing numerical standards for those events.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 105

Comment: ACC believes that it is appropriate for EPA to revisit this issue. ACC suggests that EPA propose work practice standards that would allow sources a certain time period for start-up, shutdown and malfunction events and as long as certain procedures are followed, then compliance would be met. Those work practice standards should require the development and implementation of an emissions minimization plan that will result in (a) minimizing emissions during such events that would exceed otherwise applicable emission limitations, and (b) for malfunctions that will cause the unit to exceed otherwise applicable emission limitations, promptly identifying and implementing measures to remedy the malfunction.

While there may be some instances where standard work practices can be identified for a type of source, ACC cautions that overly prescriptive and non-facility-specific requirements can actually be counterproductive, restricting the operators" flexibility in a way that hampers their ability to troubleshoot or respond to an event, or that compromises safety. The plan itself should not be incorporated into the Title V permit. The plan should be an evolving document, and it would be very cumbersome to have to seek a modification of the Title V permit every time the plan changed. If the details of the emissions minimization plan had to be made part of the permit, facilities would tend to make the plans less specific and therefore probably less useful. For the same reason, these plans should be maintained at the facility rather than being required to be submitted to the permitting authority with the Title V application or otherwise.

Alternatively, EPA could establish a threshold of exceedances either a number or percentage of operating times that could occur during a quarterly or six month period before a violation occurs.

This methodology is consistent with other MACT standards such as 40 CFR 63 Subparts S and MM.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 177

Comment: Sources Will Not Be Able To Meet Some OPLs On Startup or Shutdown. As stated in the comments related to appropriate averaging times and related to startup and shutdown, many types of control equipment are not in full operational mode while a boiler is starting up or shutting down. Therefore, OPLs will not always be feasible to meet during startup or shutdown. EPA should instead establish work practices for startup and shutdown periods, in lieu of requiring operating parameter limits to be met.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Wayne Brandt
Commenter Affiliation: Minnesota Forest Industries
Document Control Number: EPA-HQ-OAR-2002-0058-3220
Comment Excerpt Number: 6

Comment: Startup, Shutdown, Malfunction: The proposed standards do not adequately account for periods of startup, shutdown or malfunction because the EPA uses short-term performance test results to set emission limits, not the results of long-term Continuous Emission Monitoring. EPA must recognize that boilers do not run at a "steady state" condition; therefore the proposed limits cannot be met while boilers are starting up and shutting down.

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Michael A. Livermore
Commenter Affiliation: Institute for Policy Integrity, New York University School of Law
Document Control Number: EPA-HQ-OAR-2002-0058-2720.1
Comment Excerpt Number: 16

Comment: Important Improvements Made by EPA in the Proposed Rules
Start up, shut down, and malfunction rules: The previous boiler MACT proposal and the prior solid waste incinerator rules contained exceptions for otherwise applicable emissions limits during "periods of startup, shutdown and malfunction." [Footnote: 75 Fed. Reg. at 32,012] In accordance with the D.C. Circuit's opinion in Sierra Club v. EPA (2008), [Footnote: 551 F.3d 1019 (DC Cir. 2008), cert. denied, 2010 U.S. LEXIS 2265 (2010).] the current proposed rules do not contain any such exemptions, and the proposed standards would apply to regulated sources at all times. [Footnote: 75 Fed. Reg. at 32,012.]

In addition to the legal reasons contained in the D.C. Circuit's opinion, this change is also justified on policy grounds. As the proposed rule notes, startup and shutdown are entirely predictable events and can be included in the general emissions standard by EPA. [Footnote: 75 Fed. Reg. at 32,013.] By contrast, malfunction events should be entirely unpredictable and, as the preamble for the Major Source Proposal notes, the best performing sources should not be malfunctioning at all. [Footnote: 75 Fed. Reg. at 32,013.]

Response: See the preamble for changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Other - SSM

Commenter Name: Los Angeles Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1778
Comment Excerpt Number: 38

Comment: I want to underscore the importance of eliminating the malfunction exemptions. On the other rules, the exemption allows chemical plants, refineries and other major facilities to violate their emissions standards over and over and over again without any accountability.
And as you know, I have personally fought a very long battle with the Agency on the startup/shutdown of malfunction provisions. These provisions at large sources of combustion like refineries, chemical manufacturing facilities, power plants, cement kilns can double or triple emissions.
And it's very difficult with these startup/shutdown and malfunction get out of jail free cards for local citizen groups to have any kind of enforcement hook to reduce those emissions. It makes a mockery of the toxic release inventory. It makes a mockery of the permits to allow these start-up and shutdown malfunction exemptions. And so I actually copied pretty good case law from the D.C. Circuit on this and we want to make sure that these startup/shutdown malfunction provisions are closed.

Response: See preamble for response to changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Los Angeles Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1778
Comment Excerpt Number: 106

Comment: We definitely appreciate the EPA's efforts to control polluting boilers and process heaters at large facilities. In particular, we support the exclusion of exemptions for malfunctions, finally ending a loophole which allows emission sources to smother communities with pollution in blatant disregard of standards. We urge the EPA to reject calls to reopen this and other exemptions that undermine the health standards of this new regulation.

Response: See preamble for response to changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Houston Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1876
Comment Excerpt Number: 157

Comment: Especially important to us is EPA's decision to eliminate the outrageous malfunction exemption. In other words, the exemptions of our chemical plants, refineries, and other major polluters to violate the emission standards and blanket our communities in toxic pollution over and over again without any accountability.
Closing that loophole means that these facilities will have to run their boilers and process heaters responsibly. We know that powerful industry lobbyists are lining up to oppose this rule. They want loopholes and exemptions. They want the rules weakened and delayed, but these rules will prevent 4,800 unnecessary deaths every year and will save billions of dollars in costs. Lisa Jackson, do not cave in to industrial pressure. Make these rules stronger, not weaker, and we issue them without delay -- please issue them without delay.

Response: See preamble for response to changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Houston Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1876
Comment Excerpt Number: 165

Comment: Especially important to us is EPA's decision to eliminate the malfunction exemption. We believe that closing the loophole means that facilities will have to run their boilers and process heaters responsibly.

Response: See preamble for response to changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Commenter Name: Arlington Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1779
Comment Excerpt Number: 137

Comment: Especially important to us is EPA's decision to eliminate the outrageous malfunction exemption. State's emissions data have made it clear that chemical plants, refineries, and other polluters violate their emissions standards routinely during so-called malfunction events. During these events they blanket neighboring communities in toxic pollution, making people sick and forcing them to miss work, miss school, and seek medical help. These events also increase the likelihood that the people in these communities will suffer from cancer, birth defects, and other catastrophic adverse health effects. The malfunction loophole has already been held unlawful by a Federal Appeals Court. Closing it will bring an end to the abuse by ensuring that polluters can be held accountable when they violate emission standards.

One great example of that is in Corpus Christi, Texas, where it has been documented that some of the major releases –- you can actually document by the major releases the next day the number of children in emergency rooms. And you can also document the time lost by their parents from work by the number of children who are in emergency rooms and the fugitive releases and other releases in the communities in the evenings.

Response: See preamble for response to changes made in the final rule to address concerns with start-up, shutdown, and malfunction.

Recordkeeping and Reporting Requirements

Data Reporting Requirements

Commenter Name: Thomas A. Julie
Commenter Affiliation: Composite Panel Association
Document Control Number: EPA-HQ-OAR-2002-0058-2530.1
Comment Excerpt Number: 1

Comment: For all boilers and process heaters, EPA is proposing that facilities should maintain daily records of fuel use that demonstrate that they have burned no materials that are considered solid waste. See §63.7550. EPA is also proposing to require certification of the following statement on the compliance reports: ‘No secondary materials that are solid waste were combusted in any affected unit.” The requirement to certify that no solid waste was burned may not be feasible, as explained below.

CPA agrees with AF&PA’s separate comments on EPA’s waste identification rule explain that various secondary material streams that clearly constitute legitimate fuels will contain “incidental” materials that cannot practically be screened out, make no discernable difference to the environmental characteristics of the fuel stream, and either have fuel value or do not detract from fuel value. In those comments, AF&PA urged EPA, following long-established RCRA practice, to allow the burning of such incidental materials as part of the fuel stream that will inevitably contain them.

In addition, there is really no humanly possible way to prevent any discarded materials from finding their way into legitimate fuel streams. Someone at some time will throw oily rags, or waste paper, or a bandage, or earplugs, onto a bark pile or similar fuel storage facility, or a storm may blow small amounts of these materials onto a fuel storage pile.

Beyond such unavoidable events, there are also cases where it would make sense in terms of overall social policy to deliberately burn incidental materials in boilers without turning them into CISWI units. For example, the residues from cleaning up spills of non-hazardous materials, such as oil and hydraulic fluid, are often simply burned. So, on occasion, are scrubber residuals.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2797.1, excerpt 28 for a response to de minimis quantities of non-hazardous secondary materials.

Commenter Name: Paula A. Gant and Bob Beauregard
Commenter Affiliation: American Gas Association and American Public Gas Association
Document Control Number: EPA-HQ-OAR-2002-0058-2724.1
Comment Excerpt Number: 4

Comment: With regard to the tune-up required as a work practice for natural gas-fired boilers, AGA and APGA support annual reports being made available to EPA upon request.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2908.1, excerpt 13 for a response to the request to reduce reporting requirements for units only subject to work practice standards.

Commenter Name: John M. Cullen
Commenter Affiliation: Masco Corp.
Document Control Number: EPA-HQ-OAR-2002-0058-2417.1
Comment Excerpt Number: 7

Comment: Initial notification requirements in 63.7545(b) for existing boilers and process heaters is not appropriate for natural gas-fired boilers and should be clarified to exclude boilers that do not have emission limits.

Response: The EPA disagrees with the commenter, initial notification is appropriate for all existing boilers and process heaters.

Commenter Name: Britt S. Fleming
Commenter Affiliation: Auto Group
Document Control Number: EPA-HQ-OAR-2002-0058-2775.1
Comment Excerpt Number: 25

Comment: (14) Proposed § 63.7545(b), which requires Initial Notification for existing boilers and process heaters, is not appropriate for natural gas-fired boilers and should be clarified to exclude boilers that do not have emission limits. EPA has excluded from notification requirements sources that are subject to work practice standards in other MACT standards and should do the same in this rule for natural gas-fired boilers/process heaters. [Footnote: See National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines, 75 Fed. Reg. 9648, 9677 (Mar. 3, 2010) (§ 63.6645(a)(5) states that notifications are not required for those RICE covered by the rule that are subject to work practice standards).]

Response: The EPA disagrees with the commenter, initial notification is appropriate for all existing boilers and process heaters.

Commenter Name: Britt S. Fleming
Commenter Affiliation: Auto Group
Document Control Number: EPA-HQ-OAR-2002-0058-2775.1
Comment Excerpt Number: 26

Comment: (15) Proposed § 63.7545(e), which describes what must be included in the Notification of Compliance, requires further revision. This proposed provision references (e)(1) through (9) but there is no (8) and (9) included in the proposal. In addition, this proposed requirement is not appropriate for natural gas-fired boilers and should be clarified to exclude boilers that do not have emission limits. Compliance certification for remaining MACT requirements (i.e. annual tune-up) for natural gas-fired boilers and process heaters can be addressed by the existing Title V Compliance Certifications.

Response: EPA has revised the Notification of Compliance requirements to address the cross reference issue identified by the commenter. The EPA disagrees with the comment that natural gas-fired boilers should be excluded as these boilers are still subject to some of the requirements in the Notification of compliance status. Regarding Title V Compliance Certifications, the rule allow sources to submit any notification or report including those required by Title V certifications and reports.

Commenter Name: Jack Carter
Commenter Affiliation: Weyerhaeuser Company
Document Control Number: EPA-HQ-OAR-2002-0058-2797.1
Comment Excerpt Number: 28

Comment: EPA declined to address de minimis quantities of non-hazardous secondary materials in the proposed solid waste definition rule [75 FR 31844]. We believe this is not practical or realistic, and places facilities at compliance risk even for accidental or inadvertent presence of miscellaneous materials in a stockpile or storage bin of biomass fuel. EPA should address an exclusion for de minimis materials combusted in boilers and process heaters.

Response: There is no de minimis level of allowable solid waste combustion. Sources are expected to take measures to prevent the combustion of solid waste materials to the maximum extent practicable. While sources may believe it is beneficial to deliberately combust small amounts of various solid waste materials, the rule does not allow for such deliberate combustion of solid waste materials, and, based on recent court decisions, cannot allow such.

Commenter Name: Stephen R. Gossett
Commenter Affiliation: Eastman Chemical Company
Document Control Number: EPA-HQ-OAR-2002-0058-3137.1
Comment Excerpt Number: 64

Comment: EPA should clarify the notification required by § 63.7545(f) that this notification is not required when burning other gaseous fuels.

This notification is required when there is a natural gas curtailment or supply interruption. By definition, a gas-fired unit (either natural gas, refinery gas, or Gas 2) can burn fuel oil up to 48 hours without being classified as a "unit designed to burn oil". However, the wording of the notification requirement could be interpreted to be triggered when a Gas 1 unit needs to burn Gas 2 (other fuels can contribute up to 10 percent heat input annually to a Gas 1 unit). EPA should clarify the wording of this notification provision to clarify it applies to either Gas 1 or Gas 2 units that need to burn liquid fuels during a curtailment of natural gas supply interruption.

Response: The 10 percent allowance for other fuels in a Gas 1 unit is no longer in the rule. The notification is required if any other fuels are combusted with the noted exceptions for 48 hours or periodic testing, or for periods of curtailment or gas supply emergencies.

Commenter Name: Britt S. Fleming
Commenter Affiliation: Auto Group
Document Control Number: EPA-HQ-OAR-2002-0058-2775.1
Comment Excerpt Number: 65

Comment: Proposed § 63.7545(f) – This provision requires notification within 48 hours when burning backup fuel during a curtailment event. This notification does not make sense given that backup fuels are allowed by existing permits. Burning a backup fuel is not like burning a new fuel. It would be more appropriate for EPA to require identification of the use of backup fuels as part of the semi-annual compliance report for Title V. Another consideration is that sources would need more than 48 hours to provide notification, which would have to be certified by a responsible official. Furthermore, more than 48 hours may be needed in states that require electronic submittals through internet-based applications. For these reasons this requirement is unnecessary and should be deleted from the final rule.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2894.1, excerpt 6 for a response to alternative fuel use notifications.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 304

Comment: AF&PA's comments on EPA's waste identification rule explain that various secondary material streams that clearly constitute legitimate fuels will contain "incidental" materials that cannot practically be screened out, make no discernable difference to the environmental characteristics of the fuel stream, and either have fuel value or do not detract from fuel value. In those comments, AF&PA urges EPA, following long-established RCRA practice, to allow the burning of such incidental materials as part of the fuel stream that will inevitably contain them.
In addition, there is really no humanly possible way to prevent any discarded materials from finding their way into legitimate fuel streams. Someone at some time will throw oily rags, or waste paper, or a bandage, or earplugs, onto a bark pile or similar fuel storage facility, or a storm may blow small amounts of these materials onto a fuel storage pile.
Beyond such unavoidable events, there are also cases where it would make sense in terms of overall social policy to deliberately burn incidental materials in boilers without turning them into CISWI units. For example, the residues from cleaning up spills of non-hazardous materials, such as oil and hydraulic fluid, are often simply burned. So, on occasion, are scrubber residuals.

Law enforcement agencies sometimes ask facilities with boilers to help them dispose of contraband marijuana by burning it. This can be particularly true in rural areas where other disposal options are limited. AF&PA sees no reason to use CISWI to ban such useful practices. Instead, EPA should amend its CISWI rule and its Boiler rules to provide that facilities could burn incidental amounts of waste without being classified as a CISWI unit. AF&PA believes such exclusion would be entirely proper. There is a presumption in favor of agency power to establish such an exclusion. That presumption tracks back to Judge Leventhal's statement many years ago that unless Congress had been "extraordinarily rigid", agencies had inherent power to exclude from regulation cases where the gain from regulation would be of "trivial or no value". Alabama Power Co. v. Costle, 636 F.2d. 323, 360-61 (D.C. Cir. 1979).
It is true that the CISWI opinion said, 489 F.3d at 1260, that when Congress defined a "solid waste incineration unit" as a unit that burned "any" solid waste, see § CAA §129(g)(1), it meant "any" to mean "any". However, the court did not address the question of whether EPA could establish an exclusion from any such literal reading that would allow incidental amounts of solid waste to be burned with legitimate fuels. The Clean Air Act case on which the court chiefly relied also stated most strongly that "any" meant "any" and then expressly said this did not preclude a de minimis exclusion. See New York v. EPA, 443 F.3d. 880, 888 (D.C. Cir. 2006).

Moreover, the environmental petitioners in CISWI also expressly left this point open. See Brief for Environmental Petitioners at 6 (stating that "Environmental Petitioners express no view on whether EPA might be able to demonstrate on remand that [excluding a unit that sometimes burns 1% solid waste from CISWI] meets this Court's standards for establishing de minimis administrative exclusions.")

Indeed, EPA has already in effect established such exclusions in its CISWI rules. For example, the medical incinerator rules do not cover household waste (see 40 CFR §60.51c definition of "medical infectious waste"). Similarly, the proposed CISWI rule itself does not literally follow the statute. While the statute calls for EPA to establish emission limits for "any facility" that combusts solid waste, EPA's proposal would apply only to any "commercial or industrial facility" that burns such material, see proposed §60.2265, 75 Fed. Reg. 31983.

Of course EPA acted entirely properly in thus proposing to exclude home stoves and fireplaces from regulation. Excluding from regulation de minimis amounts of materials burned in larger units would be no less proper.

EPA's approach to RCRA regulation leads to the same result. Since RCRA regulation began EPA has allowed the handling and disposal of small amounts even of hazardous waste outside the RCRA system, since such an exclusion does not pose any environmental danger, while attempting to regulate such small amounts would lead to many regulatory absurdities. See generally 40 CFR 261.5 (authorizing the disposal of small quantities even of hazardous waste outside the hazardous waste regulatory system.)

For all these reasons, AF&PA urges EPA to allow non-CISWI combustion units to burn up to 1% by weight non-hazardous solid waste without becoming CISWI units.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2797.1, excerpt 28 for a response to de minimis quantities of non-hazardous secondary materials.

Commenter Name: Robert Karworski
Commenter Affiliation: Whirlpool Corporation
Document Control Number: EPA-HQ-OAR-2002-0058-2403.1
Comment Excerpt Number: 1

Comment: Notifications {Sec 63.7545}

Whirlpool Corporation believes the 48 hour notification time limit for Gas 1 units temporarily switched over to an alternate fuel is burdensome. Potentially, a weekend "switch over" may not be relayed to responsible parties until after the 48 hour period. Unlike a spill event, this information is not time critical. We requests that the notification be extended to a minimum of 72 hours.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2894.1, excerpt 6 for a response to alternative fuel use notifications.

Commenter Name: Leonard W. Sandridge
Commenter Affiliation: University of Virginia
Document Control Number: EPA-HQ-OAR-2002-0058-2769.1
Comment Excerpt Number: 21

Comment: In §63.7505(d), we suggest changing the first sentence to begin with "If you demonstrate compliance with a CEMS or operating limits, you must develop a site-specific monitoring plan..." A liquid fire boiler less than 100 MMBtu/hr heat input may be able to meet the emission limits without air pollution control equipment and would be too small to require CEMS. These facilities should not have any required continuous monitoring systems and therefore no need for a site-specific monitoring plan.

Response: EPA has revised the §63.7505(d) requirement in response to this comment and others like it.

Commenter Name: Melvin E. Keener
Commenter Affiliation: Coalition for Responsible Waste Incineration (CRWI)
Document Control Number: EPA-HQ-OAR-2002-0058-2824.1
Comment Excerpt Number: 22

Comment: As proposed, EPA requires reporting of test results within 60 days of completing each performance test. It will be difficult to get certain results back and reviewed within that time frame, and close to impossible for dioxin samples without paying a premium. EPA's current methods have the following hold times for Method 23: 21 days to extraction and 40 days from extraction to analysis. Recently, many laboratories have struggled to meet these holding times simply because of the large number of samples to be analyzed. Adding the test results from all the units in this rule will further strain the system and may cause even longer delays. CRWI suggests that this requirement be changed to 90 days.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2880.1, excerpt 67 for a response to the request for a data submission extension.

Commenter Name: Leonard W. Sandridge
Commenter Affiliation: University of Virginia
Document Control Number: EPA-HQ-OAR-2002-0058-2769.1
Comment Excerpt Number: 24

Comment: §63.7521(b) states that a fuel analysis plan must be submitted to EPA for review 60 days prior to the date the operator intends to demonstrate compliance. Can EPA review and approve these plans for all affected sources in a timely fashion for test preparation? We recommend the fuel analysis plan only be submitted upon request. The proposed regulation gives clear guidance on fuel sampling procedures and analysis requirements making mandatory review an inefficient use of EPA's time.

Response: The required submittal has been changed to a submittal upon request by the delegated authority. The plan must be developed and records maintained.

Commenter Name: Leonard W. Sandridge
Commenter Affiliation: University of Virginia
Document Control Number: EPA-HQ-OAR-2002-0058-2769.1
Comment Excerpt Number: 29

Comment: The definition for unit designed to burn gas 1 (NG/RG) subcategory includes "any boiler or process heater that burns at least 90% natural gas and/or refinery gas on a heat input basis on an annual average. Unit designed to burn oil subcategory definition states that "gaseous fuel boilers and process heaters that burn liquid fuel during periods of gas curtailment, gas supply emergencies or for periodic testing of liquid fuel not to exceed a combined total of 48 hours during any calendar year are not included in this definition."

We have 17 boilers that are designed to burn natural gas and distillate oil, many of which can meet the definitions above by only using oil during gas curtailments or restricting the annual heat input to
less than 10%. How do we document that our gas/oil boilers fall under the definition of the gas 1 subcategory? Do we need permit limits to cap the oil use to qualify? Do we submit fuel consumption data with the semi-annual report to document qualification as a gas 1 boiler? We support the latter method.

Response: EPA has revised the definition for units designed to burn gas 1 in response to this comment and others like it. Units subject to an emission limit are required to keep records of fuel usage.

Commenter Name: Chris Greissing
Commenter Affiliation: Industrial Minerals Association
Document Control Number: EPA-HQ-OAR-2002-0058-2740.2
Comment Excerpt Number: 31

Comment: (g) You must report the results of performance tests (stack test and fuel analyses) within 60 days after the completion of the performance tests.

EPA should amend paragraph (g) to provide boiler owners with 120 days to report performance test results. Due to the complexity of EPA Method 23 for dioxin/furan, there presently exists a backlog problem at many labs to complete the analytical portion of the method, sometimes extending well beyond 60 days. In addition, as a result of this rulemaking there will be a significant increase in the volume of testing and analytical work conducted nation-wide for industrial boilers and process heaters.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2880.1, excerpt 67 for a response to the request for a data submission extension.

Commenter Name: Donald R. Schregardus
Commenter Affiliation: Department of Defense
Document Control Number: EPA-HQ-OAR-2002-0058-2763.1
Comment Excerpt Number: 33

Comment: The proposed rule states that if you operate a natural gas-fired boiler or process heater that is subject to this subpart, and you intend to use a fuel other than natural gas or equivalent to fire the affected unit, you must submit a notification of alternative fuel use within 48 hours of the declaration of a period of natural gas curtailment or supply interruption.

We believe that it is EPA's intent that the 48-hour notification only needs to be submitted when the natural gas supply is curtailed or interrupted. The language could be misinterpreted to require this notification when alternative fuels are fired in a gas-fired unit during maintenance checks and readiness testing. Maintenance checks and readiness testing are routine, planned events recommended by the Federal, State or local government, the manufacturer, the vendor, or the insurance company associated with the boiler or process heater. Implementation of the test procedures require advance planning before tests are conducted; therefore, the notification submittal is unnecessary.

Revise 63.7545(f) as follows to ensure the rule allows testing without notification of alternative liquid fuel for a natural gas-fired boiler or process heater for the purpose of maintenance checks and readiness testing.
(f) If you operate a natural gas:fired boiler or process heater that is subject to this subpart, and you intend to use a fuel other than natural gas or equivalent to fire the affected unit during a period of natural gas curtailment or supply interruption, as defined in §63.7575, you must submit a notification of alternative fuel use within 48 hours of the declaration of a period of natural gas curtailment or supply interruption, ; . The notification must
include the information specified in paragraphs (f)(1) through (5) of this section.

Response: EPA agrees with the commenter and has clarified the rule requirements accordingly. For additional information on alternative fuel use notifications refer to DCN EPA-HQ-OAR-2002-0058-2894.1, excerpt 6.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-2702.1

Comment Excerpt Number: 159

Comment: Notifications
Under the Proposed Rule, an owner or operator would be required to submit notifications based on the schedule set forth in proposed § 63.7545. 75 FR 32060. The Proposed Rule is not clear whether another initial notice is required for units that filed under the prior Subpart DDDDD. EPA should clarify whether an additional notice is required for units that filed under the prior Subpart DDDD.

Response: All sources must submit the initial notification requirements for this rule, regardless of whether or not the source previously submitted an initial notification under the vacated standard. Based on responses to the survey EPA identified that many sources have switched to area sources or shutdown certain boilers since the vacated rule was finalized and the Agency needs an updated listing of affected sources.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 190

Comment: Proposed 63.7521 requires, for fuel testing, development and submission a detailed site-specific fuel analysis plan to the EPA Administrator for review and approval 60 days before testing. Since testing is required monthly, it appears this plan is required monthly, which makes no sense. Furthermore, we do not see any justification for requiring such a plan for gas- or liquid-fired boilers or process heaters, unless alternate test methods are to be used. For gas and liquid fuels we believe all that should be required, if rule methodologies are used, is a record of what fuels will be sampled and where the sample will be taken.

Recommendation: Revise 63.7521 as suggested above. Replace the requirement for developing and submitting a fuel testing plan for gas- and liquid-fired units to a recordkeeping requirement.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2769.1, excerpt 24 for a response to fuel analysis plan submittals.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 217

Comment: 7. 63.7530(e) requires You must submit the energy assessment report, along with a signed certification that the assessment is an accurate depiction of your facility, while 63.7545(g)(2) specifies that the NCS must contain a certification that This facility has had an energy assessment performed according to 63.7530(e). 63.7545(g)(2) does not require submission of the energy assessment with the NCS.

Per the requirements of Table 3, the energy assessment report will be massive and will be crammed with proprietary facility detail that must be maintained as confidential under the Confidential Business Information provisions of the CAA. Thus, submitting the detailed report serves no purpose and only greatly increases the burden imposed on regulatory agencies. Proposed 63.7530(e) should not be finalized.

Recommendation: If the energy assessment requirements are finalized, finalize proposed 63.7545(g)(2) and drop proposed 63.7530(e).

Response: EPA has dropped the requirement to submit a copy of the energy assessment in 63.7530(e) in response to comment; this is consistent with the notification requirements in 63.7545(e)(8)(ii). The certification that was in 63.7550(g)(ii) is now in 63.7545(e)(8)(ii).

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 229

Comment: Proposed 63.7545(e) specifies If you are required to conduct an initial compliance demonstration as specified in 63.7530(a), you must submit a Notification of Compliance Status according to 63.9(h)(2)(ii). For each initial compliance demonstration, you must submit the Notification of Compliance Status, including all performance test results and fuel analyses, before the close of business on the 60th day following the completion of the performance test and/or other initial compliance demonstrations according to 63.10(d)(2). The word each in the second sentence and the 60 day time requirement seems to require a separate NCS for every performance test, of which there will be a great many under this rule. To be efficient, it has been common practice historically to allow grouping of all initial performance test results and all other required NCS information into one report, due within 180 days after the compliance date of a part 63 rule.

Recommendation: Allow sources to submit one NCS report, 60 days after completion of all required initial compliance demonstrations or 180 days after the compliance date, whichever is earlier.

Response: EPA has revised the § 63.7545(e) in response to comments to clarify that the Notification of Compliance Status is for the affected source and shall be submitted 60 days after the compliance demonstration is completed for the whole affected source (i.e., after all performance stack tests are completed).

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 231

Comment: Proposed 63.7545(e)(1) specifies that the NCS contain "A description of the affected source(s) including identification of which subcategory the source is in, the design capacity of the source, a description of the add-on controls used on the source, description of the fuel(s) burned, including whether the fuel(s) were determined by you or EPA through a petition process to be a non-waste under 40 CFR 241.3, whether the fuel(s) were processed from discarded non-hazardous secondary materials within the meaning of 40 CFR 241.3, and justification for the selection of fuel(s) burned during the performance test." We have the following comments on this requirement.

The requirement should ask for the information on a boiler and process heater basis, not an affected source basis, since the existing affected source is a collection of boilers and process heaters within a subcategory.

Presumably the "capacity" information desired is the design heat duty (firing rate), not the steam generation or process fluid capacity, of the unit. This item should be revised to make that clear.

Recommendation: Clarify 63.7545(e)(1) as recommended above.

Response: EPA has revised § 63.7545(e)(1) in response to the comment and changed "source" to "unit" and "design capacity" to be "design heat input capacity."

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 232

Comment: Proposed 63.7550 specifies that semi-annual compliance reports be submitted 31 days after the end of each calendar half. Thirty-one days is inadequate time to gather, review and tabulate all of the data for all of the sources at a major site. Under this proposal, there is a massive amount of information that must be manually developed and tabulated. For instance, obtaining Hg and Cl- fuel analysis information from the outside laboratories that typically perform these analyses for the large number of units at a typical major source will require the better part of the 31 days. Furthermore, the report must provide information on performance tests performed during the reporting period and EPA normally and rightfully provides 60 days to report performance test results.

Recommendation: Require compliance reports 60 days after the end of the compliance period, rather than 30 days after.

Response: EPA has not revised the semi-annual compliance report submittal dates specified in § 63.7550. These dates are consistent with the General Provisions in 40 CFR 63 Subpart A.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 233

Comment: Proposed 63.7550(c)(4) requires submission in the compliance report of monthly fuel use data. Monthly fuel information for boilers and process heaters can be used to calculate proprietary process operating and production data. This will cause many sites to classify this data as Confidential Business Information. Furthermore, we see no reason why this information is needed. The continuing compliance monitoring provides assurance the emission limitations are being met, where there are emission limitations. For the Gas 1 category, work practice deviations are reported and there are no emission limits that involve knowing how much fuel was used. There is no obvious need for this information and, given its sensitive nature it should be removed from this report.

Recommendations: Do not finalize the requirement to report monthly fuel use data.

Response: EPA disagrees with removing this reporting requirement. This data can be used for verification of heat input, which is used in different calculations. If the item is considered as sensitive, the facility can submit the data as confidential business information if they so choose.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 234

Comment: Proposed 63.7550(c)(6) requires submission in the compliance report of information on fuels burned and their Cl- and Hg contents. This provision should only apply for units subject to Cl- or Hg emission limitations.

Recommendation: Limit 63.7550(c)(6) to only units subject to emission limits for mercury and chlorides.

Response: EPA has revised the § 63.7550(c)(6) in response to the comment.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 235

Comment: Proposed 63.7550(e) establishes reporting requirements if there is a deviation from an emission limit, operating limit, or monitoring requirement occurring at an affected source where you are using a CMS to comply with that emission limit or operating limit. However, the specific requirements seem to be a mix of deviation associated information and general information. The required information should be limited to that associated with a deviation and the subparagraphs need clarification as follows. Requiring vast listings of information on every CMS at a source serves no purpose and only burdens the source and the reviewers.

63.7550(e)(2) requires reporting of “The date and time that each CMS was inoperative, except for zero (low-level) and high-level checks.” This should be clarified that only the information on the CMS associated with the deviation is required, not all CMS being used for compliance with this rule. Also, any planned maintenance or QA/QC outage covered by the applicable monitoring plan should not have to be reported, not just zero and high level checks. For instance, required calibrations and RATA tests should also be excused from reporting. Gathering such information serves no purpose.

63.7550(e)(3) requires reporting of “The date, time, and duration that each CMS was out of control, including the information in 63.8(c)(8).” Again, this should be limited to the CMS associated with the deviation. 63.8(c)(8) already requires reporting of out-ofcontrol periods for all CMS in the compliance report, so this paragraph should only be required for out-of-control periods associated with the deviation.

63.7550(e)(5) requires reporting “A summary of the total duration of the deviation during the reporting period and the total duration as a percent of the total source operating time during that reporting period.” However, (e)(4) already requires reporting the start and stop times of the deviation and (e)(6) requires reporting the % of operating time for which there are deviations. Thus, (e)(5) is both confusing as to what it requires, but also duplicative and thus it should be deleted.

63.7550(e)(7) requires reporting “A summary of the total duration of CMS downtime during the reporting period and the total duration of CMS downtime as a percent of the total source operating time during that reporting period.” Again this should be clarified that only the information on the CMS associated with the deviation is required, not all CMS being used for compliance with this rule. Since most CMS downtime is associated with required, planned routine maintenance and QA/QC activities a general tabulation provides no value and only imposes large burdens, given the large number of CMS that will be present at a major source.

Recommendation: Clarify and revise the deviation reporting requirements.

Response: The EPA disagrees with the commenter that § 63.7550(e) is duplicative are requires revision. The subparagraphs of § 63.7550(e) require that only deviations from an emission limit be reported. It should be noted that a continuous monitoring system deviations may not be associated with an emission limit deviations.

Commenter Name: Edward Bortz
Commenter Affiliation: SP Newsprint Co LLC
Document Control Number: EPA-HQ-OAR-2002-0058-3128
Comment Excerpt Number: 3

Comment: We also encourage EPA to add materials that EPA's definition of solid waste rule ultimately defines as wastes to the list of materials that that can constitute up to 30 percent of the heat input without the boiler being considered an incinerator. In the communities where our mills are located, the boilers serve an important function to the community as the means of choice for combusting materials that we have always considered fuels but that EPA is threatening to classify as wastes. For example, if the local police or federal authorities make a drug bust or cut down a marijuana farm, it is our boiler that they turn to for destruction of the illicit material. Landfilling several hundred pounds of marijuana is not an option, nor is shipping it to an incinerator hundreds of miles away. Similarly, wood products facilities are increasingly the option of choice for combustion of separated wood deriving from construction and demolition. If these materials are classified as solid wastes, it is critical that there be an exception to allow a small amount of our overall heat input to constitute these fuels.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2797.1, excerpt 28 for a response to de minimis quantities of non-hazardous secondary materials.

Commenter Name: Pamela F. Faggert
Commenter Affiliation: Dominion
Document Control Number: EPA-HQ-OAR-2002-0058-2908.1
Comment Excerpt Number: 13

Comment: EPA should reduce or even eliminate reporting requirements for units/boilers only subject to work practice standards. Since these units are not required to install control devices, perform testing or are not subject to monitoring requirements, reporting would only consist of general facility information, fuel usage and a statement that tune-ups and energy assessment requirements were met. It is overly burdensome to require semiannual reports for this limited information.

Response: The EPA thanks the commenter for their input. The reporting requirements have modified in the final rule. For units subject to a work practice standard of an annual or biennial tune-up, the final rule requires the unit to report the date of the annual or biennial tune-up. We have reduced the compliance reporting frequency for these units to annually and biennially, respectively, instead of a standard semi-annual compliance schedule. We have added this requirement in a new paragraph 63.7550(c)(12). A report, not records, is consistent with the General Provisions in 40 CFR 63 Subpart A.

Commenter Name: Russ A. Wozniak
Commenter Affiliation: Dow Chemical Company
Document Control Number: EPA-HQ-OAR-2002-0058-2632.1
Comment Excerpt Number: 22

Comment: Table 2 Should Specify that the Averaging Time for HCl and Mercury is the Same as the Required Sampling Frequency. Section 63.7515(f) requires a monthly fuel analysis if compliance is demonstrated based on a fuel analysis for each type of fuel burned. Table 2 does not specify an averaging time for demonstrating compliance with the emission limits. Dow also supports revising the sampling frequency to semi-annual for HCl and mercury, and further comments that the averaging time should be on a semi-annual basis if this recommendation is adopted. Based on the proposed rule, at a minimum, the rule and Table 2 should state that a monthly average value should be used for HCl and mercury.

Response: The Hg and HCl limits are not based on an average. Compliance must be demonstrated each month, so no changes are needed to Tables 1 or 2 to include averaging times for Hg and HCl.

Commenter Name: J. Michael Geers
Commenter Affiliation: Duke Energy
Document Control Number: EPA-HQ-OAR-2002-0058-2765.1
Comment Excerpt Number: 34

Comment: EPA Should Give Sources at Least 45-60 days to file semi-annual reports required by Subpart DDDDD
In 63.7550, EPA requires that sources file their semiannual reports by January 31st and July 31st of each year. The regulated community is inundated with numerous other reporting requirements during this same period. Duke Energy notes that in 63.7515 (g), EPA proposes to give sources 60 days to submit emission test reports. As a result, EPA should either directly allow, or allow local permitting agencies the flexibility to grant sources a minimum of 45 days, and preferably 60days to file their semi-annual reports.

Response: EPA disagrees with the commenter. The 30 day reporting requirements is consistent with the General Provisions in 40 CFR 63 Subpart A.

Commenter Name: Pamela F. Faggert
Commenter Affiliation: Dominion
Document Control Number: EPA-HQ-OAR-2002-0058-2908.1
Comment Excerpt Number: 35

Comment: EPA should clarify that daily fuel use and operating hour records are not required for natural gas-fired units. The proposed rule is not clear regarding recordkeeping and reporting requirements for fuel use and operating hours, and preamble text and rule text are not consistent. As noted in the preamble, a reason for reporting daily fuel use is to ensure documentation of the type of fuel being combusted (e.g., solid waste is not combusted). When natural gas is the only fuel used, "fuel confirmation" can be achieved via much less onerous means than recording and reporting daily fuel use. For example, fuel type can be confirmed by the responsible company official in the compliance report. In addition, there are provisions in the rule that require notification if a fuel other than natural gas is used in a
natural gas-fired unit13. Fuel use records should not be required for natural gas-fired units complying with work practice standards, other than the annual work practice "tune up" record required in §63.7540(a)(10)(vi)(C) — i.e., "The type and amount of fuel used over the 12 months prior to the annual adjustment."
The rule text appears to limit these requirements to specific subcategories that include emission standards. §63.7550(c) contains compliance report information requirements and states in (c)(4): "The total fuel use by each affected source subject to an emission limit,..." [emphasis added]. Since natural gas-fired units are not subject to any emission limits, it appears that fuel use records or operating hour records are not required for natural gas-fired units in the rule text, but is not totally clear.
The final rule should clearly indicate that fuel use and operating hour recordkeeping and reporting requirements do not apply to natural gas-fired units subject to work practices other than the work practice requirement for an annual fuel use record. If EPA intends for more onerous requirements (e.g., daily records) for fuel use or operating hours for natural gas-fired units, the basis and associated burden for the requirement should be clearly documented and rationalized.

Response: The EPA disagrees with the commenter that the recordkeeping and reporting requirements for natural gas need clarification. Natural gas fired units are not subject to limits and do not need to keep fuel use records.

Commenter Name: Pamela F. Faggert
Commenter Affiliation: Dominion
Document Control Number: EPA-HQ-OAR-2002-0058-2908.1
Comment Excerpt Number: 36

Comment: For work practice standards, schedule requirements for tune-ups are specified in 63.7515(e). Specifically, each annual tune-up must be conducted between 10 and 12 months after the previous tune-up. Similar timing for sources subject to biennial tune-ups is not addressed. EPA should revise 63.7515(e) to provide flexibility and address biennial tune-up timing.
In some cases, an operator may have cause to conduct a tune-up more frequently that required by the rule. It is unnecessary and counter-productive for the rule to specify a minimum time of 10 months on the periodicity for annual tune-ups, as long as the maximum allowed interval is met. If a source, for whatever reason (e.g., scheduling conflicts) wants to conduct an annual tune-up sooner than 10 months after the most recent tune-up, that flexibility should be allowed. Accordingly, the following text revisions to 63.7515(e) are provided to address this issue for both annual and biennial tune-ups, "(e) If you are required to meet an applicable work practice standard, you must conduct
performance tune-ups according to 63.7540(a)(10) or (11) 63.7520. Each annual tune-up must be conducted no later than 12 months after the previous tune-up. Each biennial tune-up must be conducted no later than 24 months after the previous tune-up."

Response: Rather than requiring tune-ups to be conducted between 10 and 12 months, the final requirement is that each annual tune-up must be no more than 13 months after the previous tune-up, and each biennial tune-up must be conducted no more than 25 months after the previous tune-up.

Commenter Name: Russ A. Wozniak
Commenter Affiliation: Dow Chemical Company
Document Control Number: EPA-HQ-OAR-2002-0058-2632.1
Comment Excerpt Number: 78

Comment: As is discussed in other sections of the rule, test results must be reported within 60 days of the completion of the test. Test results for some parameters may not even be available until weeks following the completion of testing. Sixty days does not provide sufficient time to properly review all data results (including requisite quality control and assurance), perform and review the calculations and conclusions resulting from the test, prepare and certify reports and submit results electronically or manually. Similar requirements under the HWC MACT (Subpart EEE) and other MACT standards allow for reporting 90 days following testing. In addition under Subpart EEE itself, there is a provision to request additional time to complete a report in case 90 days is not enough time. Thus, the owner/operator should be provided 90 days to submit the information to EPA's WebFire database on a voluntary basis, and should be allowed to seek additional time for extenuating circumstances.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2880.1, excerpt 67 for a response to the request for a data submission extension.

Commenter Name: Russ A. Wozniak
Commenter Affiliation: Dow Chemical Company
Document Control Number: EPA-HQ-OAR-2002-0058-2632.1
Comment Excerpt Number: 80

Comment: EPA Should Not Require 48 hour Notification for Burning an Alternate Fuel Due to a Period of Natural Gas Curtailment or Interruption. Section 63.7545(f) of EPA's proposed rule requires submission of a notification of alternative fuel use within 48 hours of the declaration of a period of natural gas curtailment or supply interruption. The subsection goes on to indicate curtailment and interruption are defined in a later subsection.

Reporting of the use of alternative fuel during natural gas curtailment or interruption should be included in the semiannual compliance report as opposed to the proposed 48 hour reporting requirement for the following reasons:

EPA provides no insight or justification in the preamble or otherwise for requiring this 48 hour notification. There is no indication of how or to whom the notification is to be made. There is no definition provided for either "curtailment" or "interruption". Reporting such events within 48 hours is an unnecessary and burdensome requirement.

Reporting the use of alternative fuel within 48 hours serves no purpose. EPA proposes neither any immediate use of the notification nor any value it provides. Gas interruptions can occur during periods of adverse weather or natural disaster which could make such rapid reporting problematic.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2894.1, excerpt 6 for a response to alternative fuel use notifications.

Commenter Name: Russ A. Wozniak
Commenter Affiliation: Dow Chemical Company
Document Control Number: EPA-HQ-OAR-2002-0058-2632.1
Comment Excerpt Number: 81

Comment: EPA Should Delete the Requirements in Section 63.7550(e) since Most of This Information will be Included in the Title V Semi-Annual Deviation Report. All sources that are subject to this rule are located at a major site for HAP emissions, and thus are subject to Title V Operating Permit requirements.

The majority of the information required to be reported in proposed Section 63.7550(e) will be captured by individual state semi-annual Title V Deviation Reports. Although the details of state reporting requirements may vary some from state to state, Dow comments that EPA should rely on information provided in the respective state semi-annual deviation reports instead of creating an additional and somewhat different set of requirements for the owner/operator to have to comply with. Thus, Dow comments that the requirements in section 63.7550(e) be deleted from the final rule and that EPA simply rely on information that is reported as part of state semi-annual Title V deviation reports. State agencies should also benefit from this approach as they don't have to review similar information submitted for each boiler/heater subject to this rule.

Response: The EPA has determined that no change in § 63.7550(e) is needed. The rule already allows sources to submit Title V Semi-Annual Deviation Reports to document a deviation in this subpart.

Commenter Name: John Steber
Commenter Affiliation: Performance Fibers
Document Control Number: EPA-HQ-OAR-2002-0058-3174
Comment Excerpt Number: 1

Comment: Notifications — section 63.7545

Section 63.7545(f) states that "If you operate a natural gas-fired boiler or process heater that is subject to this subpart, and you intend to use a fuel other than natural gas or equivalent to fire the affected unit, you must submit a notification of alternative fuel use within 48 hours of the declaration of a period of natural gas curtailment or supply interruption, as defined in section 63.7575."

PFI requests clarification and guidance on the following issues related to this section:

1. Whether such a notification would apply during each curtailment event or only once a facility has reached a point where such an event would begin to compromise their ability to operate under the Gas 1 subcategory, assuming that the heat input related to the use of alternative fuels during a period of natural gas curtailment must be accounted for in assessing compliance with that subcategory.

2. The intent and purpose of requiring facilities to make such a notification — A similar requirement exists under section 63.7550(g) of the final vacated rule (69 FR 55218), presumably due to comments received based on the proposed rule (68 FR 1660) since it was not included in that document. However, PFI was unable to locate any information in the preamble of the final vacated rule or in this proposed rule related to why it was added or its intent or purpose. PFI believes such a requirement would be burdensome on both facilities and regulators and believes that natural gas curtailment or supply interruption events could be adequately monitored and enforced through recordkeeping and compliance certifications.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2894.1, excerpt 6 for a response to alternative fuel use notifications. In addition, as clarification, the notification applies to each curtailment event.

Commenter Name: Winslow Sargeant
Commenter Affiliation: U.S. Small Business Administration
Document Control Number: EPA-HQ-OAR-2002-0058-2916
Comment Excerpt Number: 3

Comment: EPA Should Have Minimized Facility Monitoring and Reporting Requirements

Several SERs noted that recordkeeping activities, as written in the vacated boiler MACT, would be especially challenging for small entities that do not have a dedicated environmental affairs department. The SERs advocated for the most efficient way to get reductions in HAP and requested that the Panel consider all available alternatives to reduce to a bare minimum any extraneous requirements that require a lot of paperwork that in the opinion of the SERs do not contribute to emission reductions.

Response: EPA must balance monitoring and reporting requirements with compliance assurance. EPA has determined that these requirements have been adequately minimized and are consistent with the General Provisions in 40 CFR 63 Subpart A.

Commenter Name: Mick Baranko
Commenter Affiliation: Douglas County Forest Products
Document Control Number: EPA-HQ-OAR-2002-0058-2856.1
Comment Excerpt Number: 5

Comment: We also encourage EPA to add materials that EPA's definition of solid waste rule ultimately defines as wastes to the list of materials that that can constitute up to 30 percent of the heat input without the boiler being considered an incinerator. In the communities where our mills are located, the boilers serve an important function to the community as the means of choice for combusting materials that we have always considered fuels but that EPA is threatening to classify as wastes. For example, if the local police or federal authorities make a drug bust or cut down a marijuana farm, it is our boiler that they turn to for destruction of the illicit material. Landfilling several hundred pounds of marijuana is not an option, nor is shipping it to an incinerator hundreds of miles away. Similarly, wood products facilities are increasingly the option of choice for combustion of separated wood deriving from construction and demolition. If these materials are classified as solid wastes, it is critical that there be an exception to allow a small amount of our overall heat input to constitute these fuels.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2797.1, excerpt 28 for a response to de minimis quantities of non-hazardous secondary materials.

Commenter Name: Bethany J. Johnson
Commenter Affiliation: The Boeing Company
Document Control Number: EPA-HQ-OAR-2002-0058-2894.1

Comment Excerpt Number: 6

Comment: Remove Requirement for Notification of Alternative Fuel Use.
Proposed section 63.7545(f) requires that, for gas-fired boilers or process heaters, a notification of alternative fuel use be submitted within 48 hours of a declaration of natural gas curtailment or supply interruption. There does not appear to be an underlying purpose for submitting such notifications (e.g. there is no requirement that alternative fuels only be used during curtailment, and there is no requirement that curtailment events be limited in number or duration). Furthermore, proposed section 63.7540(a)(10)(vi)(C) would require recordkeeping of the types and amounts of fuel used in each boiler or process heater with a heat input capacity of 10 million BTU/hour or greater in the Gas1 (NG/RG) subcategory, which would assure compliance with the proposed requirement that such units not exceed 10 percent utilization of alternative fuels on a heat input basis on an annual average. Therefore, to minimize the administrative burden of the rule on both the sources and on the EPA/delegated authorities that would receive these notifications, this notification requirement should be removed from the rule.

Response: EPA disagrees that this notice is unnecessary. The notification requirement will allow EPA to ensure that only those units that qualify as Gas 1 units remain in the Gas 1 subcategory. Other commenters have noted that curtailments are an unlikely event, so the burden of this requirement should be minimal.

Commenter Name: Jeffrey O'Hearn
Commenter Affiliation: Panolam Industries International Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2749.1
Comment Excerpt Number: 7

Comment: 63.7545(f): 48 hour notifications for natural gas fired units that are required to switch fuels due to natural gas curtailments is excessive. For these cases that are out of the control of the gas user, semi-annual reporting should be acceptable.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2894.1, excerpt 6 for a response to alternative fuel use notifications.

Commenter Name: Dennis C. McComb
Commenter Affiliation: Lincoln Paper and Tissue
Document Control Number: EPA-HQ-OAR-2002-0058-2999.1
Comment Excerpt Number: 9

Comment: LPT supports EPA’s decision to consider wastewater treatment sludge a fuel under this MACT proposal. The ability to utilize this material for energy recovery is very important to the economic viability of our Company. In addition this decision is supportive of the Maine

DEP's goals for waste minimization and the licensing of beneficial uses for these materials including fuel use.

LPT does manage other materials generated on site by burning for energy recovery. These include oily solid waste, waste cardboard, chipped pallets, and spent charcoal from air purifying units. These materials are burned in small, essentially insignificant amounts. As the rule is written to remain a boiler it appears these materials will not be able to be burned as fuel unless they are specifically approved by EPA. Absent that approval these materials will have to be landfilled which is contrary to the goals of the DEP. EPA should consider an exemption based on heat input allowing the combustion of these types of materials. The threshold could be 0.5-1% on an annual basis.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2797.1, excerpt 28 for a response to de minimis quantities of non-hazardous secondary materials.

Commenter Name: American Crystal Sugar Company and Michigan Sugar Company
Commenter Affiliation: Patricia Hansen and Steven Smock
Document Control Number: EPA-HQ-OAR-2002-0058-2970.1
Comment Excerpt Number: 18

Comment: The proposed rule contains a significant number of documentation requirements. Many of these requirements duplicate existing documentation requirements. It is understood that the agency desires proper documentation for compliance with the new rule, however the rule needs to be evaluated for duplication of existing requirements. Reference should be made to the existing federal documentation requirements. Any state documentation requirements that exceed the federal can be ignored and allow the individual states to resolve their issues.

Response: The EPA has determined that no change in documentation requirements are needed. Reporting requirements for this rule can be merged with those already required under State permitting programs.

Commenter Name: Lee B. Zeugin
Commenter Affiliation: Utility Air Regulatory Group
Document Control Number: EPA-HQ-OAR-2002-0058-2880.1
Comment Excerpt Number: 23

Comment: UARG agrees that 30-day notice of testing is reasonable, but asks that EPA add a reference in § 63.7545(d) to the provisions of § 63.7(b)(2) addressing rescheduling of tests following notice. Providing this reference would be consistent with other provisions in which EPA has cited § 63.7.

Response: EPA has revised the notification of testing requirement to 60-days to be consistent with the General Provisions in 40 CFR 63 Subpart A. The regulations indicate that all notifications in § 63.7(b) be submitted.

Commenter Name: Lee B. Zeugin
Commenter Affiliation: Utility Air Regulatory Group
Document Control Number: EPA-HQ-OAR-2002-0058-2880.1
Comment Excerpt Number: 33

Comment: Some provisions also require approval in order to move forward. [In several places, EPA uses the phrase submit for "approval upon request." See proposed §§ 63.7505(d)(1) and 63.7522(g). It is not clear if EPA is referring to a source owner/operator's request for approval, or a regulatory authority's request for submission. EPA should revise these provisions to remove this ambiguous phrase.] Although the provisions generally establish a required time-frame for submittal, e.g., 60 days before the initial performance evaluation or compliance demonstration, the rules do not impose any deadline for a response by the Administrator, permitting authority, or regulatory authority. EPA should provide that timely submitted requests for approval are automatically approved after 30 days if no response is received.

Response: EPA is referring to the delegated authority's request for submittal. Those delegated authorities that request submittal of such plans are expected to act within a reasonable time since they initiated the request. No change has been made.

Commenter Name: Michael Hutcheson
Commenter Affiliation: Ameren Services
Document Control Number: EPA-HQ-OAR-2002-0058-2803.1
Comment Excerpt Number: 35

Comment: The data required to be included in a semi-annual compliance report is overly burdensome and requires the permittee to develop and submit more information than is relevant to self reporting of compliance conditions. The US EPA should consider reducing these self reporting burdens to the minimum necessary to determine compliance. The US EPA seems to have transitioned from not only requiring soures to self-report deviations, but must also report data from compliance calculations for HCL or Hg. You must submit notices of intent to perform stack testing (in addition to those required by 40 CFR 63 Subpart A), copies of test reports (in addition to those required by Subpart A), the data from CMS performance reports (presumably this information must also be submitted in the CMS performance reports required), descriptions of each source and CMS system as well as changes to that CMS. The amount of data and information required to be included the twice yearly report is not insignificant and the US EPA is apparently requiring significant amounts of information that is required to be submitted by Subpart A be submitted again.

Response: EPA has not revised the semi-annual compliance report data requirements. Much of the data reporting and notifications are the same as in General Provisions in 40 CFR 63 Subpart A, but are just repeated in the rule for clarity.

Commenter Name: Traylor Champion
Commenter Affiliation: Georgia-Pacific LLC
Document Control Number: EPA-HQ-OAR-2002-0058-2745.1
Comment Excerpt Number: 41

Comment: EPA should extend the date for completion of the energy assessment report.
In the proposed rule, at §63.7545(g)(2), EPA specifies that the energy assessment must be completed by the compliance deadline and noted in the notice of compliance status. The Agency should allow a reasonable time following the final compliance deadline because there are no compelling reasons for requiring such an early completion. Indeed, as discussed above, mill and corporate staff will be fully engaged with selecting, installing and starting up the extremely complex control equipment that will be required for meeting emission limitations imposed by this rulemaking in a very short timeframe. Then for the next eight months following the compliance deadline, the facilities will be conducting the required emission testing and preparing the detailed test reports and compliance status reports required by the MACT General Provisions (40 CFR Part 63 Subpart A). Therefore, EPA should allow 18 months following the deadline for submission of the compliance status report for completion of the energy assessment report.

Response: We disagree with the comment that the completion date for the energy assessment should be extended past the proposed compliance date. The requirement for conducting an energy assessment only applies to existing facilities. The date for an existing facility to achieve compliance is 3 years after publication of the final rule. Three years is the maximum compliance period allowed under section 112 of the Clean Air Act. We believe that 3 years is more than sufficient considering that an energy assessment can be conducted in a manner of a few days. In the final rule, we have revised the definition of an energy assessment to include the maximum length of time to conduct an energy assessment at a small (one day) and medium (3 days) boiler energy use facility.

Commenter Name: Lee B. Zeugin
Commenter Affiliation: Utility Air Regulatory Group
Document Control Number: EPA-HQ-OAR-2002-0058-2880.1
Comment Excerpt Number: 67

Comment: Proposed § 63.7550(h) requires reporting of test data to EPA within 60 days after completion of the performance evaluation. 75 Fed. Reg. at 32,062. Section 63.7(g) (applicable under Table 10) states that a performance test is "completed" when the field sample collection is terminated. Although receiving the analytical results of performance tests within 60 days generally is not a problem, it could be a problem for some tests -- like Method 23 for D/F -- that require intense laboratory procedures and for which there may only be a limited number of qualified laboratories. UARG requests that EPA include a provision allowing additional time for submittal of the results of D/F tests, if necessary.

Response: The dioxin testing requirement is now a one-time test, and sources have ample time (three years) to plan their test so as not to miss the submittal date for the initial compliance test. However, EPA recognizes the potential for backlog of laboratories and test contractors that have the capabilities to collect and analyze dioxin data and, therefore, is extending the time period to 90 days.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 226

Comment: INCIDENTAL USE OF NON-HAZARDOUS SOLID WASTE SHOULD BE PERMITTED. For all boilers and process heaters, EPA is proposing that facilities should maintain daily records of fuel use that demonstrate that they have burned no materials that are considered solid waste. See proposed section 63.7550. EPA is also proposing to require certification of the following statement on the compliance reports: ""No secondary materials that are solid waste were combusted in any affected unit." The requirement to certify that no solid waste was burned may not be feasible, as explained below.

Our comments on EPA’s waste identification rule explain that various secondary material streams that clearly constitute legitimate fuels will contain "incidental" materials that cannot practically be screened out, make no discernable difference to the environmental characteristics of the fuel stream, and either have fuel value or do not detract from fuel value. ACC urges EPA, following long-established RCRA practice, to allow the burning of such incidental materials as part of the fuel stream that will inevitably contain them.

It should be recognized that it is nearly impossible to prevent any discarded materials from finding their way into legitimate fuel streams. Someone at some time will throw oily rags, or waste paper, or a bandage, or earplugs, onto a bark or coal pile or similar fuel storage facility, or a storm may blow small amounts of these materials onto a fuel storage pile.

Beyond such unavoidable events, there are also cases where it would make sense in terms of overall social policy to deliberately burn incidental materials in boilers without turning them into CISWI units. For example, the residues from cleaning up spills of non-hazardous materials, such as oil and hydraulic fluid, are often simply burned. So, on occasion, are scrubber residuals.

On quite a different note, law enforcement agencies sometimes ask facilities with boilers to help them dispose of contraband marijuana by burning it. This can be particularly true in rural areas where other disposal options are limited. ACC sees no reason to use CISWI to ban such useful practices.

Instead, EPA should amend its CISWI rule and its Boiler rules to provide that facilities could burn incidental amounts of waste without being classified as a CISWI unit. ACC believes such exclusion would be entirely proper. There is a presumption in favor of agency power to establish such an exclusion. That presumption tracks back to Judge Leventhal's statement many years ago that unless Congress had been "extraordinarily rigid", agencies had inherent power to exclude from regulation cases where the gain from regulation would be of "trivial or no value".[Alabama Power Co. v. Costle, 636 F.2d. 323, 360-61 (D.C. Cir. 1979).]

In vacating the CISWI Definitions Rule, the D.C. Circuit Court stated that when Congress defined a 'solid waste incineration unit" as a unit that burned "any" solid waste, it meant "any" to mean "any". [NRDC v. EPA, 489 F.3d 1250, 1260 (D.C. Cir. 2007).] However, the court was not asked to address the question of whether EPA could establish an exclusion from any such literal reading that would allow incidental amounts of solid waste to be burned with legitimate fuels. The Clean Air Act case on which the court chiefly relied also stated most strongly that "any" meant "any" and then expressly said this did not preclude a de minimis exclusion. [See New York v. EPA, 443 F.3d. 880, 888 (D.C. Cir. 2006).] Moreover, the environmental petitioners in CISWI also expressly left this point open. [See NRDC v. EPA, 489 F.3d 1250 (D.C. Cir. 2007).]

Indeed, EPA has already in effect established such exclusions in its CISWI rules. For example, the medical incinerator rules do not cover household waste (see 40 CFR section 60.51c definition of "medical infectious waste"). Similarly, the proposed CISWI rule itself does not literally follow the statute. While the statute calls for EPA to establish emission limits for "any facility" that combusts solid waste, EPA's proposal would apply only to any "commercial or industrial facility" that burns such material.[75 Fed. Reg. at 31983, Proposed section 60.2265. Brief for Environmental Petitioners at 6 (stating that "Environmental Petitioners express no view on whether EPA might be able to demonstrate on remand that [excluding a unit that sometimes burns 1% solid waste from CISWI] meets this Court's standards for establishing de minimis administrative exclusions.")]

Of course EPA acted entirely properly in thus proposing to exclude home stoves and fireplaces from regulation. Excluding from regulation incidental amounts of materials burned in larger units would be no less proper.

EPA's approach to RCRA regulation leads to the same result. Since RCRA regulation began EPA has allowed the handling and disposal of small amounts even of hazardous waste outside the RCRA system, since such an exclusion does not pose any environmental danger, while attempting to regulate such small amounts would lead to many regulatory absurdities. See generally 40 CFR 261.5 (authorizing the disposal of small quantities even of hazardous waste outside the hazardous waste regulatory system.)

For all these reasons, ACC urges EPA to allow non-CISWI combustion units to burn incidental amounts (e.g., up to 1% by weight) of non-hazardous solid waste without becoming CISWI units. EPA should revise the recordkeeping and reporting requirements in this Boiler rule to accommodate incidental amounts of non-hazardous solid waste.

Response: Daily records are not required. This was an error in the preamble that has been removed. Refer to DCN EPA-HQ-OAR-2002-0058-2797.1, excerpt 28 for additional information on de minimis quantities of non-hazardous secondary materials.

Records That Must Be Retained

Commenter Name: Carter Strickland, Jr
Commenter Affiliation: New York City Department of Environmental Protection
Document Control Number: EPA-HQ-OAR-2002-0058-1600.1
Comment Excerpt Number: 7

Comment: Reduce bookkeeping requirements. DEP contracts for its fuel on a long-term basis and does not use any solid fuel. Accordingly, daily fuel records are not necessary to prove that solid fuels are not used. Similarly, the various notices required to conduct performance tests, establish compliance status, and to use alternative fuels, should be greatly simplified to reflect the operational needs and standards in operating wastewater treatment plants.

Response: We have modified the daily fuel use records to monthly basis in accordance with the commenter's request. The notifications in this rule are consistent with those listed in the general provisions, but we have reduced some bookkeeping requirements since proposal in order to reduce the burden to the extent possible.

Commenter Name: Michael L. Steele
Commenter Affiliation: CraftMaster Manufacturing, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-1907.1
Comment Excerpt Number: 31

Comment: It is requested that recordkeeping of fuel use be on a monthly basis, not daily. We cannot directly measure our dry biomass fuel. A material! heat balance is performed each month.

Response: The final rule requires, monthly fuel use records be kept.

Commenter Name: William C. Herz
Commenter Affiliation: The Fertilizer Institute
Document Control Number: EPA-HQ-OAR-2002-0058-1910.1
Comment Excerpt Number: 5

Comment: In the proposed rule, EPA proposes that all boilers and process heater units maintain daily records of fuel use that demonstrate that a facility has burned no materials that are

considered solid waste. 75 Fed. Reg. at 32,015. This requirement requires facilities to prove a negative and should be reconsidered.
TFI requests that all natural gas-fired boilers and process heater units be exempt from this requirement, as these units are not configured to burn solid waste. If EPA does not exempt natural gas units from this requirement, TFI requests that EPA redefine this requirement so that facilities are required to maintain records of the specific days on which a unit burns materials that may be considered solid waste. If EPA does not redefine the requirement, TFI asks for some guidance on how a facility demonstrates that it has burned no solid waste materials on a given day.

Response: Daily records are not required. This was an error in the preamble that has been removed. Refer to DCN EPA-HQ-OAR-2002-0058-2797.1, excerpt 28 for additional information on de minimis quantities of non-hazardous secondary materials.

Commenter Name: Michael Palazzolo
Commenter Affiliation: Alcoa Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2967.1
Comment Excerpt Number: 3

Comment: Section 63.7540(a)(10)(vi)(C) of the proposed rule would require the owner/operator to record the amount of natural gas burned in each gas-fired metal processing furnace. Most of these furnaces do not currently have natural gas meters and the capital cost to install these meters will be $15,000 to $20,000 per furnace. For several Alcoa facilities, the cost to purchase and install natural gas meters would be in excess of $1,000,000, which does not include ongoing maintenance, calibration and data acquisition costs. Tracking natural gas consumed per furnace is not necessary for proper burner maintenance, and maintenance records from burner tune-ups and CO levels will provide the Agency adequate documentation to verify that annual tune-ups have been completed. Furthermore, data on the amount of natural gas used will not provide an indication of burner performance during any 12-month period. Higher or lower gas use during any 12-month period will only be a function of variability in furnace operation (cycle times, operating temperatures and load size) over the 12 months. The requirement to install gas meters and record amount of gas burned should therefore be deleted from the proposed rule.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2729.1, excerpt 21 for a response to concerns related to fuel use recordkeeping and individual gas meters.

Commenter Name: Paula A. Gant and Bob Beauregard
Commenter Affiliation: American Gas Association and American Public Gas Association
Document Control Number: EPA-HQ-OAR-2002-0058-2724.1
Comment Excerpt Number: 6

Comment: We request that EPA revise its proposal to eliminate the requirement to record the amount of fuel consumed for boilers or process heaters that only use natural gas. As long as natural gas is the sole fuel consumed in a boiler or process heater, the amount of fuel consumed is irrelevant to the other requirements in the rule. Moreover, the installation of fuel meters or other fuel estimation methods would be overly burdensome without sufficient cost justification in terms of hazardous emissions reporting. An owner or operator should be permitted to report that only natural gas has been combusted in the affected source in lieu of reporting the amount of fuel consumed. A requirement to report the amount of natural gas consumed in those circumstances would only create a disincentive for boiler and process heaters to use clean-burning natural gas versus another fuel.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2729.1, excerpt 21 for a response to concerns related to fuel use recordkeeping and individual gas meters.

Commenter Name: Lisa Beal
Commenter Affiliation: Interstate Natural Gas Association of America
Document Control Number: EPA-HQ-OAR-2002-0058-2756.1
Comment Excerpt Number: 11

Comment: EPA should clarify that keeping records of daily fuel use and operating hours is not required for natural gas-fired units.

The proposed rule is not clear regarding recordkeeping and reporting requirements for fuel use and operating hours, and preamble text and rule text are not consistent. Fuel use and operating hour recordkeeping and reporting requirements should be clarified.

As noted in the preamble, a reason for reporting daily fuel use is to ensure documentation of the type of fuel being combusted (e.g., solid waste is not combusted). However, for natural gas-fired units in gas transmission systems, natural gas will be the only fuel used and "fuel confirmation" can be achieved via much less onerous means than recording and reporting daily fuel use. For example, fuel type can be confirmed by the responsible company official in the compliance report. In addition, there are provisions in the rule that require notification if a fuel other than natural gas is used in a natural gas-fired unit. Fuel use records should not be required for natural gas-fired units complying with work practice standards, other than the annual work practice "tune up" record required in §63.7540(a)(10)(vi)(C) – i.e., "The type and amount of fuel used over the 12 months prior to the annual adjustment."

The preamble indicates that fuel use and operating hour records are required for natural gas-fired units. For example, the preamble indicates:

"For all boilers and process heaters, we are proposing that you maintain daily records of fuel use that demonstrate that you have burned no materials that are considered solid waste."

We are proposing that you must keep the following records:

(4) Daily hours of operation by each source.” [75 FR 32015]

And,

“We are also requiring that you keep daily records of the total fuel use by each affected source, subject to an emission limit or work practice standard,...” [75 FR 32035]

However, the proposed regulations appear to limit these requirements to specific subcategories – e.g., the requirement for fuel use records applies to units that include emission standards. For example, §63.7550(c) indicates compliance report information requirements and includes the following in (c)(4):

“(4) The total fuel use by each affected source subject to an emission limit,...” [emphasis added] In addition, §63.7545(f) requires notification for natural gas-fired units that intend to use a different fuel:

“(f) If you operate a natural gas-fired boiler or process heater that is subject to this subpart, and you intend to use a fuel other than natural gas or equivalent to fire the affected unit, you must submit a notification of alternative fuel use within 48 hours of the declaration of a period of natural gas curtailment or supply interruption, as defined in § 63.7575. The notification must include the information specified in paragraphs (f)(1) through (5) of this section.”

Thus, the objective to ensure that only natural gas is used for natural gas-fired units is addressed. Daily fuel use records or operating hour records do not appear to be explicitly required for natural gas-fired units in the rule text, but the rule is not clear.

INGAA recommends that the final rule clearly indicate that fuel use and operating hour recordkeeping and reporting requirements do not apply to natural gas-fired units subject to work practices other than the work practice requirement for an annual fuel use record. Confusion caused by text cited above should be clarified. The final rule should clearly indicate that §63.7545(f) provides assurance on fuel type for natural gas-fired units and 63.7540(a)(10)(vi)(C) identifies the requirement for annual fuel use records for units subject to work practices. If EPA intends for more onerous requirements (e.g., daily records) for fuel use or operating hours for natural gas-fired units, the basis and associated burden for the requirement should be clearly documented and rationalized.

Response: The final rule requires, monthly fuel use records be kept. It should be noted that monthly records apply only to units subject to limits in Tables 1 or 2. Fuel use records also included as part of the annual or biennial tune-up requirement specified in 63.7540(a)(10)(vi)(C).

Commenter Name: Britt S. Fleming
Commenter Affiliation: Auto Group
Document Control Number: EPA-HQ-OAR-2002-0058-2775.1
Comment Excerpt Number: 17

Comment: Requirement for Individual Gas Meters in § 63.7540(a)(10)(vi)(C) Is Unnecessarily Burdensome.

The proposed work practice requirement for natural gas-fired boilers and process heaters in § 63.7540(a)(10)(vi)(C) would require a source to include in the on-site annual report the "type and amount of fuel used over the 12 months to the annual adjustment." This proposed requirement is of concern to the Auto Group. Most facilities do not have individual gas meters for tracking the amount of fuel used on the smaller in-plant boilers and process heaters. In fact, EPA has allowed many companies to apportion natural gas fuel usage to boilers subject to the industrial boiler New Source Performance Standards (NSPS), Subpart Dc, or keep a record of the fuel delivered to the property during the calendar month. [Footnote: See 40 C.F.R. § 60.48c(g)(3).] In addition, new reporting requirements of GHG emissions also are accomplished on a facility-wide basis and utilize the billing data from the main meter for the facility (or group of facilities).

Installing separate meters would be incredibly expensive, especially for complex manufacturing sources that have numerous affected sources. For example, one company participating in the Auto Group has 12 boilers and process heaters at a single facility. With an individual meter costing between $10,000-15,000 to install, a facility would have a compliance cost range of $120,000-180,000 just for the individual gas meters alone. While auto companies already are tracking and reporting fuel use on a facility wide basis for Title V annual emission reports and other state regulatory requirements, this data is on total fuel use and not on a boiler/process heater-specific basis. EPA needs to further explain and justify why this burdensome requirement is necessary for all the natural gas units given that individual gas usage data would not provide any useful information and is not necessary to demonstrate that a tune-up has been properly performed.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2729.1, excerpt 21 for a response to concerns related to fuel use recordkeeping and individual gas meters.

Commenter Name: Steven M. Maruszewski
Commenter Affiliation: The Pennsylvania State University
Document Control Number: EPA-HQ-OAR-2002-0058-2729.1
Comment Excerpt Number: 21

Comment: Small Boilers - Tune-ups for boilers under 10 MMBtu
PSU has approximately 73 boilers on contiguous property that meet this definition. An existing Preventative Maintenance program and schedule already exists. Also, it is required that the type of fuel and annual fuel use for each boiler is recorded. For
natural gas, the meters are at the building-level or even a group of buildings, not at the unit. There is no way to distinguish between fuel use for the boiler and other equipment in the building. This could be significant for research buildings or residential buildings with laundry and food service equipment. Providing this data on a boiler-by boiler-basis will require the

installation of additional meters. Unit fuel type and total group fuel use is already required as part of the GHG Mandatory Reporting Rule. The tune-up and fuel use recordkeeping and annual report creation will be arduous for large institutional facilities with many units. HAP reductions for these units will be negligible compared to complying large units. Penn State recommends that EPA drop the boiler-by-boiler fuel use recordkeeping requirement.

Response: Based on other comments, the record of fuel type and use in 63.7540(a)(10)(vi)(C) was revised so that it only needs to be kept if the unit is physically and legally capable of using more than one fuel type. This would exclude many natural gas fired institutional boilers that do not have a back up fuel. In addition, EPA has added the following language so as not to require units that use a single gas meter to install additional meters: For multiple units with a single gas meter, record the total usage for all units subject to the tuneup requirement in lieu of a unit-by-unit record.

Commenter Name: Myra C. Reece
Commenter Affiliation: South Carolina Department of Health and Environmental Control
Document Control Number: EPA-HQ-OAR-2002-0058-2525.1
Comment Excerpt Number: 23

Comment: Reconcile Daily Versus Monthly Fuel Records

As prescribed in the preamble section G(6) (75 FR 32014), section G(7) (75 FR 32015), section K (75 FR 32033), and section N (75 FR 32035), daily records of fuel use are to be maintained by each affected source; however, only monthly records of fuel use are to be maintained in accordance with 63.7555(5)(d)(1). The EPA needs to clarify if affected sources are required to maintain daily or monthly records of fuel use. As the EPA has set precedent (EPA 4APT-ATMB letter to SCDHEC dated March 7, 2002) by stating monthly records of fuel use for units subject to 40 CR 60 Subpart Dc can be maintained for natural gas fired units as well as distillate oil fired units, we agree with this record keeping approach for these types of units. Daily records for other fuel subcategories may be more appropriate to determine compliance with emission limits, fuel analysis protocol, or work practice standards as outlined in the referenced preamble sections above.

Response: EPA has revised the final rule to require that affected sources maintain daily records of fuel use.

Commenter Name: Britt S. Fleming
Commenter Affiliation: Auto Group
Document Control Number: EPA-HQ-OAR-2002-0058-2775.1
Comment Excerpt Number: 46

Comment: Proposed § 63.7555(d)(1), which requires monthly fuel usage records for all boilers and process heaters, is a problem since facilities do not have separate meters for every process heater and boiler. Many facilities have centralized gas meters and do not have separate metering of the small boilers and process heaters. It should be sufficient to demonstrate compliance by keeping records of the fuel type burned (i.e., landfill gas) and information concerning the design maximum heat input (i.e., mmBtu/hr). See the discussion above regarding separate metering.

Proposed § 63.7555(d)(4), which requires calculation of a HCl emission rate for each boiler and process heater, does not make sense where sources use gaseous fuels from a common distribution system since the gaseous fuel would be the same for each unit. See the discussion above regarding separate metering.

Proposed § 63.7555(d)(5), which requires calculation of a mercury emission rate for each boiler and process heater, also is ill-suited for sources using gaseous fuels from a common distribution system since the gaseous fuel would be the same for each unit.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2729.1, excerpt 21 for a response to concerns related to fuel use recordkeeping and individual gas meters.

Commenter Name: Britt S. Fleming
Commenter Affiliation: Auto Group
Document Control Number: EPA-HQ-OAR-2002-0058-2775.1
Comment Excerpt Number: 67

Comment: Proposed § 63.7555 Subsection (d)(7), which requires that if a source operates a gaseous fuel unit that is subject to the emission limits specified in Table 1 or 2 to this subpart, and you intend to use a fuel other than natural gas or equivalent to fire the affected unit, you must keep records of the information required by the notification under § 63.7550, and records of the total hours per calendar year that liquid fuel is burned. If the other fuel is landfill gas (note that the fuel does not necessarily have to be a liquid fuel), then the only requirements should be related to the other fuel usage rates (e.g., cubic feet per month or gallons per month).

Response: EPA agrees with the commenter and has clarified the requirements accordingly. Section 63.7555(d)(7) has been deleted and a new paragraph added under 63.7555(h) with adjusted language. This adjusted language specifies record keeping for "other" gas usage, not just liquid fuels.

Commenter Name: Donald R. Schregardus
Commenter Affiliation: Department of Defense
Document Control Number: EPA-HQ-OAR-2002-0058-2763.1
Comment Excerpt Number: 31

Comment: The requirement to install a continuous emission monitoring system (CEMS) for CO should only apply to units that are subject to a CO emissions limit.

We do not believe that EPA expects units that are not subject to a CO emissions limit to install a CO CEMS. The final rule should be clarified to prevent this situation.

Revise §63.7525(a) as follows:
"If your boiler or process heater has a heat input capacity of 100 MMBtu per hour or greater and is subject to a CO limit, you must install, operate, and maintain a continuous emission monitoring system for CO and oxygen according to the procedures in paragraphs (a)(1) through (6) of this section by the compliance date specified in § 63.7495. The CO and oxygen shall be monitored at the same location at the outlet of the boiler or process heater.

Response: EPA has revised the rule to address the comment. It should be noted that the final rule now requires only an oxygen monitor.

Commenter Name: Donald R. Schregardus
Commenter Affiliation: Department of Defense
Document Control Number: EPA-HQ-OAR-2002-0058-2763.1
Comment Excerpt Number: 32

Comment: The preamble of the proposed rule states that the daily records of fuel use are necessary to ensure that the affected source is complying with the emission limits from the correct subcategory. §63.7555(d)(1) indicates that monthly records are required for units that are subject to emission limits.

Fuel switching is not a daily event and therefore a monthly record is sufficient to ensure that the affected source is complying with the emission limits from the correct subcategory.

The fuel use recordkeeping requirement should remain on a monthly basis as proposed in 63.7555(d)(1). Recordkeeping should only be required when unit is in operation.

Response: EPA has not revised the fuel use records requirements in § 63.7555(d)(1). The final rule requires, monthly fuel use records be kept.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 237

Comment: Proposed 63.7560(c) requires that You must keep each record on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to 63.10(b)(1). You can keep the records off site for the remaining 3 years. Since most records are computerized and computer data storage is often not onsite, most rules now require either the 2 year on-site storage or ready access of computerized records from onsite. This paragraph should be modified to reflect the current state of technology.

Recommendation: Clarify 63.7560(c) to indicate that ready access of computerized records from onsite meets the two year onsite retention requirement.

Response: EPA has revised the record retention specifications in § 63.7560(c) to allow access from an on site computer network.

Commenter Name: William C. Herz
Commenter Affiliation: The Fertilizer Institute
Document Control Number: EPA-HQ-OAR-2002-0058-2874.1
Comment Excerpt Number: 4

Comment: In the proposed rule, EPA proposes that all boilers and process heater units maintain daily records of fuel use that demonstrate that a facility has burned no materials that are considered solid waste. 75 Fed. Reg. at 32,015. This requirement requires facilities to prove a negative and should be reconsidered.
TFI requests that all natural gas-fired boilers and process heater units be exempt from this requirement, as these units are not configured to burn solid waste. If EPA does not exempt natural gas units from this requirement, TFI requests that EPA redefine this requirement so that facilities are required to maintain records of the specific days on which a unit burns materials that may be considered solid waste. If EPA does not redefine the requirement, TFI asks for some guidance on how a facility demonstrates that it has burned no solid waste materials on a given day.

Response: Daily records are not required. This was an error in the preamble that has been removed. Refer to DCN EPA-HQ-OAR-2002-0058-2797.1, excerpt 28 for additional information on de minimis quantities of non-hazardous secondary materials.

Commenter Name: Bethany J. Johnson
Commenter Affiliation: The Boeing Company
Document Control Number: EPA-HQ-OAR-2002-0058-2894.1
Comment Excerpt Number: 4

Comment: Fuel Usage Tracking should not be required where only one fuel may be burned. Proposed 40 CFR 63.7540(a)(10)(vi)(C) requires that at major sources for each boiler or process heater with a heat input capacity of 10 million BTU/hour or greater in the Gas 1 (NG/RG) or

Metal Process Furnace subcategories, a record be maintained of the type and amount of fuel used over the 12 months prior to each annual adjustment. Presumably, this is to be able to demonstrate that the unit meets the fuel usage restrictions for its subcategory. However, for boilers and process heaters that are physically or lawfully incapable of burning more than a single type of fuel (e.g., a natural gas fired boiler that is physically incapable of burning any other fuel, or a natural gas fired boiler that while physically capable or burning another fuel is legally prohibited from doing so even at times of natural gas curtailment, gas supply emergencies, etc.), there is no underlying reason to track the amount of fuel usage at this level. In many cases, fuel consumption at small boilers is not individually tracked or recorded and adding metering equipment and recordkeeping processes would impose additional expense without corresponding environmental benefit. We ask that this requirement be modified to exempt sources that are incapable of burning more than a single type of fuel. We suggest the following modification to proposed section 63.7540(a)(10)(vi)(C):

"The type and amount of fuel used over the 12 months prior to the annual adjustment, but only if the unit was physically and legally capable of using more than one type of fuel during that period."

Response: EPA has added the suggested language to § 63.7540(a)(10)(vi)(C).

Commenter Name: Jeffrey O'Hearn
Commenter Affiliation: Panolam Industries International Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2749.1
Comment Excerpt Number: 8

Comment: 63.7555(d)(7): This item is a bit unclear as to actually what records from § 63.7550 are required. Further clarification is needed.

Response: We have modified the language in (d)(7) and replaced it with a new paragraph (h). This new paragraph clarifies that the records needed are the total hours per calendar year of fuels combusted in the unit other than natural gas, refinery gas, or other on-spec gas 1 fuel.

Commenter Name: Gary Melow
Commenter Affiliation: Michigan Biomass
Document Control Number: EPA-HQ-OAR-2002-0058-2776.1
Comment Excerpt Number: 19

Comment: EPA proposes to require daily records of fuel types burned to demonstrate that no solid waste has been fired (75 FR at 32015). This is a burdensome requirement. Fuel specifications are established to ensure each supplier provides the correct type and quality of the fuel.

Response: Daily records are not required. This was an error in the preamble that has been removed. Refer to DCN EPA-HQ-OAR-2002-0058-2797.1, excerpt 28 for additional information on de minimis quantities of non-hazardous secondary materials.

Commenter Name: David O'Keefe
Commenter Affiliation: USEC, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-3122
Comment Excerpt Number: 28

Comment: Daily records of quantity, type, and origin of each fuel burned. This requirement is not achievable and conflicts with the monthly requirements in § 63.7550 and § 63.7555. It may not be possible to determine the origin of the fuel in the cases of a mixed coal pile from several sources and a mixed fuel oil tank from several sources. Daily fuel usage for facilities that do not have direct measurement systems such as coal weigh hoppers, belts or feed systems would have the added daily burden of calculating and recordkeeping activities for fuel usage when these facilities are only making fuel calculations on a monthly basis for permit compliance demonstration or other regulatory requirements. Some facilities proportionally average fuel parameters over much longer time periods (i.e., monthly) which provides more accurate values. EPA should require this information on a monthly basis, although there may be daily recording of steam produced, feed water temperature, etc.

Response: EPA has revised § 63.7555(e) in response to the comment and changed the heat input record requirements from daily to monthly. It should be noted that emission averaging compliance § 63.7522 is based on monthly heat inputs.

Commenter Name: Bill Wemhoff
Commenter Affiliation: National Rural Electric Cooperative Association
Document Control Number: EPA-HQ-OAR-2002-0058-2835.1
Comment Excerpt Number: 31

Comment: EPA's proposal includes requirements for the tracking of numerous data points, including fuel consumption; operating hours, startups, shutdowns including dates and times; equipment malfunctions including dates and times; numerous operating parameters including dates and times of deviations; GEMS, GOMS, and GPMS calibration and quality assurance/quality control data; GEMS, GOMS and GPMS maintenance information; GEMS, GOMS, and GPMS out of control periods including reasons, dates and times; performance test reports; fuel sampling reports; vendor reports; and a number of other pieces of information. Records must be kept of virtually all information referenced in the proposal, including all GPMS data required to be collected, for five years. Unfortunately, much of these data gathering requirements cannot be automated, but instead will have to be collected manually. Once the data are gathered, decisions will have to be made regarding what has to be reported and a report will have to be generated and certified. This will be a massive undertaking and the possibility of making an error during the process will be a virtual certainty.

To reduce manpower requirements most sources will likely attempt to automate as much of the reporting and record keeping as possible. The equipment costs alone for implementing an automated (to the extent possible) data collection and report generation system for a unit with multiple controls is likely to be very high and there may be little opportunity for standardization of the software. In short, NREGA does not believe that EPA, in proposing its enforceable operating limit approach, has adequately estimated or considered the data management costs of its proposal and requests that the agency do so.

Response: EPA has determined that the record keeping requirements are consistent with both the General Provisions in 40 CFR 63 Subpart A and other Clean Air Act programs using similar monitoring technologies and reflect the minimum requirements needed to demonstrate initial and continuous compliance.

Commenter Name: Christopher S. Colman
Commenter Affiliation: Hovensa LLC
Document Control Number: EPA-HQ-OAR-2002-0058-2863.1
Comment Excerpt Number: 48

Comment: Proposed Rule Language §63.7540(a)(2):
"As specified in §63.7550(c) you must keep records of the type and amount of all fuels burned in each boiler or process heater during the reporting period....."
Comments:
It is unclear whether the fuel use must be monitored by each heater and boiler or for the aggregate of all existing heater and boilers within a subcategory. As defined above, records must be maintained for each fuel burned in each boiler and heater subject to the rule. However, §63.7550(c)(4) defines the reporting requirements as the total fuel used by each affected source subject. The definition of affected source found in §63.7490(a)(1) as the collection of all existing boilers within a subcategory at a major source. The fuel monitoring requirement language is confusing and contradictory. Thelanguage should be revised to clarify whether the fuel must be monitored and reported on a per boiler and/or heater basis or for the aggregate of all units within a subcategory.
Fuel use records for Gas 1 heaters and boilers, as required under §63.7540(a)(10)(vi)(C), should be only required as an aggregate of those sources, since mo emission limits apply to them. In a refinery, these units typically have aggregate meters for refinery fuel gas.

Response: The EPA has determined that the reporting requirements are clear and no rule change is needed. Fuel must be monitored and reported on a per boiler and/or heater basis as each unit shall demonstrate compliance with the applicable emission limits unless a facility is using the emission averaging provision among similar existing units. It should be noted that the report described in § 63.7550(c) can include records from more than one unit.

Commenter Name: Lee B. Zeugin
Commenter Affiliation: Utility Air Regulatory Group
Document Control Number: EPA-HQ-OAR-2002-0058-2880.1
Comment Excerpt Number: 68

Comment: EPA's proposal includes requirements for tracking of numerous data points, including fuel consumption; operating hours, startups, shutdowns including dates and times; equipment malfunctions including dates and times; numerous operating parameters including dates and times of deviations; CEMS, COMS, and CPMS calibration and quality assurance/quality control data; CEMS, COMS and CPMS maintenance information; CEMS, COMS, and CPMS out of control periods including reasons, dates and times; performance test reports; fuel sampling reports; vendor reports; and a number of other pieces of information. Records must be kept of virtually all information referenced in the proposal, including all CPMS data required to be collected, for 5 years. Proposed §§ 63.7555, 63.7560. Unfortunately, much of these data gathering requirements cannot be automated, but instead will have to be collected manually. Once the data are gathered, decisions will have to be made regarding what has to be reported and a report will have to be generated and certified. This will be a massive undertaking and the possibility of making an error during the process will be a virtual certainty.

Response: EPA has not revised the semi-annual compliance report data requirements. Much of the data reporting and notifications are the same as in General Provisions in 40 CFR 63 Subpart A, but are just repeated in the rule for clarity.

Electronic Reporting Mechanism

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute and National Petrochemical and Refiners Association
Document Control Number: EPA-HQ-OAR-2002-0058-0851.1
Comment Excerpt Number: 13

Comment: The rule requires performance test results be submitted to the Agency in a specific electronic format. This will be additional effort for the performance test contractor and that extra cost and effort is not included in the burden estimate.

Production losses will be incurred under the provisions of this rule for process shutdowns associated with the burner tune-up requirements and special, uneconomic operations associated with the performance test requirements. This production related cost must be taken into account in evaluating this proposal.

Response: See the preamble for discussion of the electronic reporting mechanism.

Commenter Name: Renee Lesjak Bashel
Commenter Affiliation: Small Business Ombudsman and Small Business Environmental Assistance Programs
Document Control Number: EPA-HQ-OAR-2002-0058-2854.1
Comment Excerpt Number: 5

Comment: Recommendation: Take the burden off smaller sources for providing data electronically. Consultant costs will be prohibitive, alongside the already high cost of testing. We suggest those having no units over 100 MMBTU/hr be allowed out of that requirement, but if that's too high for EPA then at a minimum those having only units 10 MMBTU/hr and lower should be exempt from that requirement.

At a recent training program, one of the SBEAPs reportedly learned that it can take a person—with experience using computers—a couple days to enter all the data into EPA's online system as required in 63.7550(h). The consultant fee was reportedly thousands of dollars, just for the data entry. If they cannot afford to have someone else enter the data, small business owners and their staff often lack basic computer use experience sufficient to maintain the most basic records and spreadsheets much less use a complex application on their own. In addition, many small businesses may not have the computing power to deal with a program in Microsoft Access and transfer files that it generates.

Until EPA can streamline this system and make it something anyone can easily use, the burden of online data entry should be left to the larger major sources that are better able to afford the cost.

Response: See the preamble for discussion of the electronic reporting mechanism.

Commenter Name: Sharene Shealey
Commenter Affiliation: RRI Energy
Document Control Number: EPA-HQ-OAR-2002-0058-2759.1
Comment Excerpt Number: 5

Comment: In cases where an ICI Boiler is part of a Title V or state only operating permit, the local permitting agency has its own unique emission and compliance test reporting format. State and local agencies also enforce the specific conditions within these operating permits. In all locations where RRI Energy operates an industrial boiler, we are required to submit a hard copy of all compliance test results to the local permitting authority. To comply with the proposed rule, RRI Energy would be required to prepare a hard copy report for the state or local agency that issued the permit in addition to inputting the data into the Electronic Reporting Tool (ERT) or WebFIRE database when it becomes available. This is a duplication of effort, increasing the cost of reporting test information.

RRI Energy would like EPA to provide a listing of those states who will utilize the ERT or WebFIRE as its means of collecting emission test data to determine compliance.

Where a state or local agency does not adopt the ERT or WebFIRE reporting mechanism, or until such time local agencies do adopt the ERT or WebFIRE reporting, the regulated entity should not be required to duplicate reporting efforts. In these cases, compliance would be demonstrated by reporting in accordance with the permitting authority's requirements.

Response: See the preamble for discussion of the electronic reporting mechanism.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 305

Comment: The requirement for ERT reporting should be removed. Industry had many problems submitting Industrial Boiler MACT and CISWI ICR data using the ERT, and there are still many problems with the tool based on experience that utilities and testing firms are having while entering Utility Boiler MACT ICR data into the tool. Use of this tool will add cost and burden to the already costly emissions testing requirements in this rule. The tool is not a replacement for a stack test report, but rather an additional reporting burden, as permitting agencies will still require a hard copy stack test report with all supporting documentation.
The following are examples of issues encountered with the ERT:

* It is not intuitive and it is difficult to use.
* It is not set up to handle data from multiple stacks from the same source being tested at the same time.
* It only allows for one intermittent leak check during a test run. Many stacks have more than two ports so the ERT should be set up to handle those scenarios rather than having to add leak check volumes together to come up with a total.
* It is not set up to handle mixed blend calibration gases, which are extremely common.
* The import tool is inadequate, as it does not have enough rows for long runs and often imports data in the wrong order.
* The tool is not set up to handle blank corrections.
* The tool is "buggy" and slow to respond.
* The tool seems to only be designed to work under the most ideal of test scenarios, which is not always realistic. The EPA should ask for comments on the format and uploading tool from individuals that encounter actual real world scenarios for testing to incorporate into future editions.
* Revisions to the ERT should have a revision number such that the users can make sure the version they are using is the most recent version available.

Response: See the preamble for discussion of the electronic reporting mechanism.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 307

Comment: Compliance tests are submitted to the state or local permitting agency for review and approval. At times, the agency provides comments to the regulated facility that adjust the test results. In these cases, the information entered into the ERT at the time of the stack test would not match the final, state-approved emission test results. At a minimum, there needs to be a mechanism for the ERT data to be updated in these situations or a flag to indicate whether the report has been reviewed and approved by the permitting agency.

Response: See the preamble for discussion of the electronic reporting mechanism.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 308

Comment: EPA could require the permitting agency to enter the stack test results into the ERT once approved, rather than requiring facilities to enter the data.

Response: See the preamble for discussion of the electronic reporting mechanism.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 309

Comment: If use of the ERT is required, EPA needs to develop a comprehensive ERT Guidance Manual that provide complete instructions with examples for:
* all entries including:
* the various facility identification codes, and where to find them
* BDL instructions
* calibration instructions
* required attachments
* the “external” spreadsheets” that are used to import certain data into the ERT
* the “external spreadsheets” that are used for reporting test methods not currently supported by the ERT

EPA should also develop an “outreach” or “training” program that provides instructions for specific source categories and related parameters. Such efforts need to be readily-available – via presentations at relevant conferences/seminars, as well as web-based sessions (”webinars”).

Response: See the preamble for discussion of the electronic reporting mechanism.

Commenter Name: Robert D. Morrison
Commenter Affiliation: Abbott Laboratories
Document Control Number: EPA-HQ-OAR-2002-0058-2764.1
Comment Excerpt Number: 17

Comment: The proposed Boiler MACT rule includes a proposed requirement that all emission test results are to be submitted electronically, however, the Electronic Reporting Tool (ERT) that has been proposed as the reporting platform is inefficient and unworkable, and should be replaced with a more flexible and user-friendly electronic reporting tool (40 CFR 63.7550(h) and 75 FR 32015). Abbott supports USEPA’s intention to streamline reporting requirements through the use of electronic data transfer. However, we have significant concerns regarding ERT as it currently exists. ERT was required for data transfer from the testing program for USEPA’s 2009 Boiler MACT Section 114 request, which required extensive boiler testing. In that program, ERT proved to be an awkward, inefficient tool, and ultimately required two different reporting procedures and a delay in data submission due to the limitations of ERT. Abbott strongly recommends that a more flexible and user-friendly electronic reporting resource should be developed. An explicit regulatory reference for use of ERT without a commitment to improve it will have an immediate impact on facilities with new units, perhaps sooner than ERT can be revised, and existing units will also be impacted at some point.

Response: See the preamble for discussion of the electronic reporting mechanism.

Commenter Name: Randall D. Quintrell
Commenter Affiliation: Georgia Paper and Forest Products Association, GPFPA
Document Control Number: EPA-HQ-OAR-2002-0058-2905
Comment Excerpt Number: 23

Comment: The proposed Rule’s requirement to use the Electronic Reporting Tool (ERT) for reporting test results is premature and ill-conceived. The ERT is, at least at present, a very poorly designed system which is very difficult to use. EPA does not even have a final version available for the regulated community to vet. Moreover, with the proposed testing requirements for inherently low emission units, it is known that many data points will be at or below the method detection limits and practical quantitation limits. Such data should not be reported electronically unless and until EPA has both developed and published (i) acceptable method detection levels and practical quantitation limits for dioxin/furan, mercury and HC1 testing, and (ii) protocols for handling non-detect data and data below the PQL. The ERT may eventually have a consistent format but that does not mean it has appropriate QA/QC functions. It also requires dedicated staff at EPA to provide quality assurance review of the data being submitted for the several thousand boilers subject to the Rule to ensure that the data are indeed valid and accurate before allowed into the database. Such method development, pre-reporting QA/QC criteria and post-reporting QA/QC validation are critically important to ensure that test results will be handled consistently and to prevent data which have not been subjected to adequate QA/QC from being made available for public distribution. Given that the Rule affects thousands of units with operators most of whom have never used a tool like the ERT the opportunity for error is significant, especially when combined with the poor design of the current ERT system. The potential damage caused by dissemination of inaccurate data is substantial. Moreover, it is counterproductive to EPA's stated purpose of generating meaningful accurate data for use as emission factors. To repeat the well known adage, "bad data is worse than no data" because it misinforms and leads to erroneous conclusions and bad decisions. The chance that this can and will happen with EPA electronic databases is illustrated by EPA's recent release of 2009 TRI data. Those data also are submitted electronically with a program does not allow the data to be viewed by the submitter for typographical errors or other mistakes after submission. The July 2010 data release was made without even providing the submitter an opportunity to review the data for such errors before it was made available to the public. Such reporting can always be added to Title V permits at a later date if and when EPA develops and maintains a properly designed system with necessary QA/QC criteria. In short, the requirement for electronic reporting using the ERT must be removed from the final Rule.

Response: See the preamble for discussion of the electronic reporting mechanism.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-2702.1
Comment Excerpt Number: 157

Comment: Emission Reporting Tool (ERT) Problems
EPA is requiring submission of data via the Electronic Reporting Tool (ERT). 75 FR 32015. Notwithstanding EPA's assertions to the contrary, data submitted through the ERT is error-prone and imposes additional burdens on reporting sources because the ERT bypasses all data quality control. For the information collection process for the Boiler MACT suite of rules, EPA required sources to use the ERT. Sources had requested in the ICR proposal stage that EPA not utilize the ERT, which was going through Beta testing, and informed EPA that the ERT had serious flaws including difficulty of use, content problems and inaccessibility. EPA decided to use it for data collection for these rules. The concerns proved correct, however, as sources were compelled to use the ERT, which is a difficult and time-consuming tool for submission of test data. The ERT data compiled was riddled with mistaken entries, incorrect and missing data, and the ERT had generally faulty output. Then the problem was compounded when EPA relied on the inaccurate data, leading to multiple calculation and other inaccuracies.

Using the ERT doubles the burden on sources that take the time to enter accurate source data, only to see it distorted. They then must spend hours finding the data error and conferring with EPA personnel to fix the problem. Only then are they able to consider EPA's rule proposal and its impact on their sources. In part due to the ERT and resulting data problems, regulated sources sought an extension of the comment period. See Comment Extension Request, especially Description of the Development of the Boiler MACT Database (see submittal for comment extension request).

Response: See the preamble for discussion of the electronic reporting mechanism.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-2702.1
Comment Excerpt Number: 158

Comment: In the past, sources did compliance tests for the state, and the state approved the data. The state effectively conducted quality control on the data. The ERT bypasses the state, creating data quality issues. Using the ERT means that data is transmitted without any QC, and that results in multiple data errors. The ERT does not permit the easy identification or correction of errors. Reporting needs to be accomplished by whatever format permits the source to trace the same data throughout the process to ensure its integrity. This had been accomplished in the past by using the hard copy submitted to the State and a human looking at data to QC it. If there was a problem, this could be identified and resolved in the early stage, before the faulty data was applied to formulas.

CIBO urges EPA to adopt a reporting methodology that ensures the data is quality controlled, and errors can be traced easily to their origins. The ERT needs to be improved before it is required for data submission for compliance demonstration. Inaccuracies may be more tolerable during the rule-writing process, but once the rules are in place, the stakes are much higher, as faulty ERT output can create compliance issues for sources. EPA may prefer the administrative ease of the ERT, but that should not outweigh the need for regulated sources to have assurances of accurate data and compliance status.

Response: See the preamble for discussion of the electronic reporting mechanism.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 183

Comment: Proposed 63.7550(h) requires electronic reporting of all performance test results for performance tests required under this rule. We see no value in this requirement for CO from gas or oil-fired boilers and process heaters and recommend its deletion. There is no justification for imposing this requirement. The preamble attempts to justify the extra cost and burden of this requirement (which is significant for the multitude of sources subject to this proposal) on the basis that it will help improve emission factors and reduce the burdens associated with collecting data on emissions through 114 requests. We see no way collecting any amount of additional data would significantly improve the emission factors for gas or oil-fired boilers for CO, versus simply calculating the CO emissions using the extremely low emission limitation in this proposal. Furthermore, collecting thousands of CO performance test results doesn't help develop emission factors, because performance tests are all run at >80% of design firing and thus do not represent normal operation or normal operating variability for the vast majority of boilers or process heaters. Since the CO limits apply at all times, they are a much better approximation basis for emission estimating than any emission factor developed from performance test data on sources subject to such low emission limits.

Recommendation: Delete the electronic reporting requirement at least for CO from oil and gas fired units subject to CO emission limitations. Consider eliminating the electronic reporting requirement for other pollutants, since the arguments above also apply to them.

Response: See the preamble for discussion of the electronic reporting mechanism.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 184

Comment: The rule requires performance test results be submitted to the Agency in a specific electronic format. This will be additional effort for the performance test contractor because this requirement does not replace the need for a written report for site records and for submission to permitting authorities. In fact, it is unclear it replaces the General provisions requirement to submit a full report to EPA.

Recommendation: If electronic reporting requirements are maintained, clarify that the electronic submission of performance test results to EPA satisfies all EPA performance test reporting requirements.

Response: See the preamble for discussion of the electronic reporting mechanism.

Commenter Name: Matthew Todd and David Friedman

Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 230

Comment: We also request any performance tests submitted to the Agency through the electronic reporting system be exempted from the requirement to include those reports in the NCS, though the electronic submission should be referenced. There is no reason to require both. If a delegated authority wants a hard copy, their regulations will require it, but there should be no need for making both types of submissions to EPA.

Recommendation: Remove the requirement to submit performance test reports in the NCS, if the final rule requires them to be submitted electronically.

Response: See the preamble for discussion of the electronic reporting mechanism.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 294

Comment: The proposed rule would require facilities to report test data using EPA's Electronic Reporting Tool. Stack test and analytical laboratories typically provide results via hardcopy test reports. The cost of contracting a test firm to enter data into the electronic database was not included in the annual stack testing costs.

Response: See the preamble for discussion of the electronic reporting mechanism.

Commenter Name: Frank Kohlasch
Commenter Affiliation: Minnesota Pollution Control Agency
Document Control Number: EPA-HQ-OAR-2002-0058-2773.1
Comment Excerpt Number: 1

Comment: Support the deployment of the Electronic Reporting Tool. The MPCA supports use of the Electronic Reporting Tool (ERT) for collecting performance test data, and encourages the U.S. Environmental Protection Agency (EPA) to properly assign resources to complete its development, as well as provide sufficient technical support for states to access submitted data in a timely fashion.

In addition to substantiating this proposed rule making, the MPCA believes when this database is available and populated, it will support a number of important aspects of the federal and state air quality programs such as improving emission inventories and air modeling inputs, as well as streamlining our assessment of emission tests and compliance determination.

It will be critical that this method of data collection and submittal be fully functional so that facility owners subject to this standard are not required to duplicate submissions to EPA and states.

Response: See the preamble for discussion of the electronic reporting mechanism.

Commenter Name: Jon T. Howard
Commenter Affiliation: Weston Solutions, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2737.1
Comment Excerpt Number: 10

Comment: Our experience with the ERT on both the Boiler MACT/CISWI and Electric Utility ICRs has not been positive. It is based on an “armchair” approach to source testing and does not allow for adjustments in data collection that are necessary to accommodate sampling at each source. We both appreciate and understand the need to expedite data transfer and eliminate the need for re-entry of data; however, the current version of the ERT is difficult and time-consuming to use. WESTON relies extensively on electronic data capture and reporting for emission testing projects. Even so, we believe that - depending on the scope of work - use of EPA’s ERT and SRTs add 8 to 24 hours per source for a mid-professional level person with previous ERT experience.

Response: See the preamble for discussion of the electronic reporting mechanism.

Commenter Name: John Hopewell
Commenter Affiliation: American Coatings Association
Document Control Number: EPA-HQ-OAR-2002-0058-2886.1
Comment Excerpt Number: 28

Comment: The requirement for ERT reporting should be removed.

Response: See the preamble for discussion of the electronic reporting mechanism.

Commenter Name: Pamela F. Faggert
Commenter Affiliation: Dominion
Document Control Number: EPA-HQ-OAR-2002-0058-2908.1
Comment Excerpt Number: 38

Comment: The ERT was used extensively in the Boiler MACT and EGU MACT ICRs. Reporting emissions data using the ERT is time consuming and represents an unnecessary burden to the regulated community. Compliance data reporting software should minimize the burden on the regulated community by requiring only those data required to demonstrate compliance. This would include the raw emissions data and a limited amount of boiler and control device operating information from the emissions test period. It should also follow a transparent development process that includes feedback from the regulated community. The proposed use of the ERT does not meet either of these requirements. We recommend that EPA eliminate this requirement from the proposed rule.

Response: See the preamble for discussion of the electronic reporting mechanism.

Commenter Name: Chris M. Hobson
Commenter Affiliation: Southern Company
Document Control Number: EPA-HQ-OAR-2002-0058-2741.1
Comment Excerpt Number: 67

Comment: EPA proposes that, after December 31, 2011, sources must submit all compliance test results to EPA using the Electronic Reporting Tool (ERT) software or "other compatible electronic spreadsheet". The ERT was used extensively in the Boiler MACT and EGU MACT ICRs. Our experience with this software suggests that reporting emissions data using the ERT is time consuming and represents an unnecessary burden to the regulated community. We recommend that EPA eliminate this requirement from the proposed rule unless or until EPA can establish the necessary statutory authority to develop such software.

Assuming EPA can establish such authority, compliance data reporting software should minimize the burden on the regulated community by requiring only those data required to demonstrate compliance. This would include the raw emissions data and a limited amount of boiler and control device operating information from the emissions test period. It should also follow a transparent development process that includes feedback from the regulated community. [Footnote: EPA followed this process in their development of the Clean Air Markets Division (CAMD) Emissions Collection and Monitoring Plan System (ECMPS) software.] The proposed use of the ERT does not meet either of these requirements.

Response: See the preamble for discussion of the electronic reporting mechanism.

Commenter Name: Russ A. Wozniak
Commenter Affiliation: Dow Chemical Company
Document Control Number: EPA-HQ-OAR-2002-0058-2632.1
Comment Excerpt Number: 77

Comment: Section 63.7540(a)(9)(iv) of EPA's proposed rule requires that, after December 31, 2011, all test data used to demonstrate compliance be entered electronically into EPA's WebFire database within 60 days of completing a performance demonstration.

EPA provides no insight or justification in the preamble or otherwise for requiring this form of data submittal. The cost of this requirement, as compared to conventional reporting, is not evaluated or disclosed in discussion of the cost and impact of the proposed rule. Although a number of affected facilities may be already trained and equipped to accomplish such electronic reporting, many of the affected facilities have not had to participate in such reporting procedures in the past. These facilities will require additional staff time, equipment and training to accomplish this requirement. The proposed effective date of this requirement means that even the initial reporting must be conducted electronically. This further burdens the affected facilities in unnecessarily having to develop new reporting techniques and procedures concurrent with the other tasks required to implement a new rule. EPA has failed to describe any benefit of this requirement as compared to these additional burdens.

Response: See the preamble for discussion of the electronic reporting mechanism.

Commenter Name: Russ A. Wozniak
Commenter Affiliation: Dow Chemical Company
Document Control Number: EPA-HQ-OAR-2002-0058-2632.1
Comment Excerpt Number: 79

Comment: It is also likely that implementation of the initial testing, much less any later testing, will be accomplished under state authority. Unless state agencies are willing to use this same electronic reporting tool, facilities will have a dual requirement for reporting. EPA has also failed to describe any effort to convince state agencies to use this tool as their preferred reporting mechanism.

Response: See the preamble for discussion of the electronic reporting mechanism.

Commenter Name: Shelley Schneider
Commenter Affiliation: Nebraska Department of Environmental Quality
Document Control Number: EPA-HQ-OAR-2002-0058-2820.1
Comment Excerpt Number: 3

Comment: The proposed standards require sources to submit their performance test data electronically to EPA through the WebFIRE software. NDEQ appreciates that having the data submitted electronically will produce a larger data set EPA can utilize to develop more accurate emission factors. Conversely, if sources are not required to submit a paper copy of the test results to the state/local permitting authority, the data can not be reviewed and quality assured. The WebFIRE software does not have quality assurance flags to alert EPA that a test was conducted improperly or whether the data is accurate. Utilizing inaccurate or false data could lead to nonrepresentative emission factors and potential noncompliance with the emission limits.

NDEQ requests EPA include a provision to require facilities to submit their testing results to their state/local permitting authority in addition to submitting the data electronically. The Nebraska Air Quality Regulations require facilities to provide emissions test results to NDEQ within 45 days of completion of the test. Not including this provision in the standard may unnecessarily result in noncompliance with the state regulations and may result in inaccurate test data.

Response: See the preamble for discussion of the electronic reporting mechanism.

Commenter Name: Wayne J. Galler and Deborah A. Phillips
Commenter Affiliation: Georgia Industry Environmental Coalition, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2882.1
Comment Excerpt Number: 14

Comment: The proposed requirement to use EPA's Electronic Reporting Tool (ERT) for reporting stack testing results is premature and ill-conceived. The ERT is, at least at present, a very poorly designed system making it extremely difficult to use. For example, the program is not designed to allow the user to review the work to correct errors or omissions before the information is submitted. Numerous other problems also exist with the software that are described in more detail in GPFPA's comments. These problems need to be addressed and corrected by EPA before this tool can be easily used by industry,otherwise, the tool will become an administrative burden, adding cost and time to industry's compliance requirements.

Response: See the preamble for discussion of the electronic reporting mechanism.

Commenter Name: Martha E. Rudolph
Commenter Affiliation: State of Colorado
Document Control Number: EPA-HQ-OAR-2002-0058-2940.1
Comment Excerpt Number: 14

Comment: The State intends to continue to request sources to submit stack test reports to the State, in addition to EPA's collecting stack testing data via the Electronic Reporting Tool (ERT). The State appreciates EPA's need to readily access stack test data and applauds efforts to improve emission factors. However, the State believes that the stack test data reported must be considered along with additional, specific information for each source's operations. This evaluation cannot be easily conducted with the limited data reported in the ERT. The State believes that the stack test data submitted in the ERT, taken at face value, may be misleading unless the context in which the testing was completed is understood. Until the number and degree of source configuration and operation variables can be adequately accounted for and reported in one reporting tool, allowing the associated test data to be wholly considered, the State will continue to request stack test reports be submitted to the State.

Response: See the preamble for discussion of the electronic reporting mechanism.

Commenter Name: Barry Christensen
Commenter Affiliation: Occidental Chemical Corp
Document Control Number: EPA-HQ-OAR-2002-0058-2848.1
Comment Excerpt Number: 17

Comment: Webfire needs a mechanism to capture Confidential Business Information (CBI). OCC respectfully requests that since EPA is requiring the use of Webfire to submit stack test information, EPA establish a mechanism in the final rule to allow facilities to submit information related to actual process operating conditions to EPA as "confidential business information," entitled to the usual protections against disclosure to the public by the EPA.

Response: See the preamble for discussion of the electronic reporting mechanism.

Commenter Name: Bill Wemhoff
Commenter Affiliation: National Rural Electric Cooperative Association
Document Control Number: EPA-HQ-OAR-2002-0058-2835.1
Comment Excerpt Number: 30

Comment: NRECA objects to EPA's proposed requirement to report using the electronic reporting tool ("ERT") and disagrees with EPA's assertions regarding the impact of that requirement on reporting and on emission factor development. As UARG notes in its comments, while experience with the ERT has been limited, industry nonetheless has identified a number of shortcomings in the programs. Furthermore, use of 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. It also is subject to significant performance issues, including software crashes and shutdowns, inoperable features (like report generation), and inadequate identification of errors preventing data analysis. In short, even if EPA can justify a requirement to report performance test data electronically, EPA cannot justify requiring sources to use this program.

Response: See the preamble for discussion of the electronic reporting mechanism.

Commenter Name: Traylor Champion
Commenter Affiliation: Georgia-Pacific LLC

Document Control Number: EPA-HQ-OAR-2002-0058-2745.1
Comment Excerpt Number: 42

Comment: The requirement to report the results of emissions testing and collateral data using the Emission Reporting Tool (ERT) needs to be re-evaluated. Georgia-Pacific's experience is that the version of the ERT that existed during the Phase II data collection testing (2009) was difficult and cumbersome to use and not sufficiently robust to handle all the data given the lack of guidance provided by EPA concerning parametric reporting for that effort. To that extent, only one of nine facilities' environmental personnel completed the ERT; all others had to pay the testing contractor additional money to do the reporting.
Looking forward, the difficulty of ERT use for the average environmental coordinator at any given location suggests that more of this work will be contracted out in the future. This would result in both additional expense to the location and in unnecessary administrative compliance risk simply because it would be difficult for that environmental coordinator to adequately review stack tester data input for correctness and completeness absent a fundamental working knowledge of ERT and how its database works. In short, it would be very easy for a stack tester to mischaracterize some aspect of the facility in the ERT that may not be caught by the submitting facility personnel.

ERT is simply not reliable enough or robust enough to be used as compliance tool under the MACT standard.

Response: See the preamble for discussion of the electronic reporting mechanism.

Commenter Name: Traylor Champion
Commenter Affiliation: Georgia-Pacific LLC
Document Control Number: EPA-HQ-OAR-2002-0058-2745.1
Comment Excerpt Number: 43

Comment: The ERT is in Microsoft® Access, a software platform that has some serious inherent weaknesses. We found this to be increasingly slower to update the more records we put in. In some cases, we had to combine records instead of reporting individual process records simply because the ERT was not robust enough to handle the level of detail we were prepared to put in the system. Access also appears to "automatically update" the ERT records file every time we opened it as opposed to asking us if we wanted to save changes. This file update makes it impossible to make an archival electronic copy of the ERT records file for reference unless the file was never to be opened again for any other purpose.

Response: See the preamble for discussion of the electronic reporting mechanism.

Commenter Name: Traylor Champion
Commenter Affiliation: Georgia-Pacific LLC

Document Control Number: EPA-HQ-OAR-2002-0058-2745.1
Comment Excerpt Number: 44

Comment: We also observed a very clear lack of instruction on how to set up records in the entry screens. The examples listed below are not intuitive; we simply arrived at these by trial and error.
o It was not at all clear that calibration sets needed to be set up as pre-requisites for run files, and that each calibration gas for each parameter needed to have a unique name even though the gases may have come from the same bottle.
o It was not at all clear how or if process data record numbers correspond to actual test run numbers. Further, it was not at all clear why process run numbers appeared to be limited to some small number less than 20.
o It was not intuitive how to add or delete records.

Response: See the preamble for discussion of the electronic reporting mechanism.

Commenter Name: Traylor Champion
Commenter Affiliation: Georgia-Pacific LLC
Document Control Number: EPA-HQ-OAR-2002-0058-2745.1
Comment Excerpt Number: 45

Comment: The report viewers in the ERT did not give us the “full” results of our data entry. This could result in remnants of “unintended for submission” remarks or comments from draft entry hanging around in the database without the facility realizing they were there in there even after reviewing the full report in the report viewers. In essence, we could be certifying the submission of something we did not even know was there. This is unacceptable.

Response: See the preamble for discussion of the electronic reporting mechanism.

Commenter Name: Traylor Champion
Commenter Affiliation: Georgia-Pacific LLC
Document Control Number: EPA-HQ-OAR-2002-0058-2745.1
Comment Excerpt Number: 46

Comment: The process data parameters in the ERT were automatically generated based on SCC Code but, in our case, some of these parameters provided little or no substantive data to correlate to the stack test. This only served to provide additional confusion to the facility.

Response: See the preamble for discussion of the electronic reporting mechanism.

Commenter Name: Traylor Champion
Commenter Affiliation: Georgia-Pacific LLC
Document Control Number: EPA-HQ-OAR-2002-0058-2745.1
Comment Excerpt Number: 47

Comment: The help tips were problematic in the ERT, as they both "ran off the screen" and were insufficient in providing guidance or resolving issues.

Response: See the preamble for discussion of the electronic reporting mechanism.

Commenter Name: Traylor Champion
Commenter Affiliation: Georgia-Pacific LLC
Document Control Number: EPA-HQ-OAR-2002-0058-2745.1
Comment Excerpt Number: 48

Comment: The ERT was not compatible with all pollutants. No guidance was provided as to when to report oxygen or carbon dioxide (at least one of these was used as a diluent for all other pollutant runs). The ERT asked for redundant data (e.g. run duration plus start and end times). The F-factor field was confusing and the ERT did not distinguish between a blank and a zero. So, for example, we used Fc. We had no need for Fw and didn't enter or address it. Instead of the ERT properly characterizing Fw as blank, the final report showed Fw = 0, which is clearly not what we intended.

Response: See the preamble for discussion of the electronic reporting mechanism.

Commenter Name: Traylor Champion
Commenter Affiliation: Georgia-Pacific LLC
Document Control Number: EPA-HQ-OAR-2002-0058-2745.1
Comment Excerpt Number: 49

Comment: The report printout mixed up labels with values. For example, it reported "#Error" as the average for the analyzer serial number, which clearly should have been a character field.

Response: See the preamble for discussion of the electronic reporting mechanism.

Commenter Name: Traylor Champion
Commenter Affiliation: Georgia-Pacific LLC
Document Control Number: EPA-HQ-OAR-2002-0058-2745.1
Comment Excerpt Number: 50

Comment: The indexing of stack test run numbers was cumbersome. The program picked run numbers sequentially instead of allowing a facility to enter something much easier for identification. So, for example, we needed to know that runs number 23 to 25 were CO runs to find out anything about them after data entry, instead of allowing us to enter an identifier like "CO Run 1", "CO Run 2", or "CO Run 3." In a related matter, the numbering conventions did not allow associations. For example, oxygen tests run simultaneously with CO could have been numbered 1 and 23, respectively, but not the more-intuitive "O2 Run 1" and "CO Run 1."

Response: See the preamble for discussion of the electronic reporting mechanism.

Commenter Name: Traylor Champion
Commenter Affiliation: Georgia-Pacific LLC
Document Control Number: EPA-HQ-OAR-2002-0058-2745.1
Comment Excerpt Number: 51

Comment: We found the pick list run number sorting sequence bothersome. Given the numbers 1, 10, 11, and 2, the more intuitive sequence of 1, 2, 10, and 11 is not used by Access. Rather, the pick list puts these in this order: 1, 10, 11, and 2.

Response: See the preamble for discussion of the electronic reporting mechanism.

Commenter Name: Lee B. Zeugin
Commenter Affiliation: Utility Air Regulatory Group
Document Control Number: EPA-HQ-OAR-2002-0058-2880.1
Comment Excerpt Number: 62

Comment: UARG objects to EPA's proposed requirement to report using ERT and disagrees with EPA's assertions regarding the impact of that requirement on reporting and on emission factor development. On December 14, 2009, UARG provided comments in response to the Agency's Advance Notice of Proposed Rulemaking ("ANPR") at 74 Fed. Reg. 52,723 (Oct. 14, 2009) soliciting comment on a number of aspects of emission factor development, including the possibility of requiring submission of all compatible Part 60 and Part 63 to WebFIRE using ERT. EPA-HQ-OAR-2009-0174-0040 (incorporated by reference). In those comments, UARG noted that its members' experience with ERT was limited, but nonetheless noted a number of shortcomings in the program that were sufficient by themselves to cause UARG to object to any requirement to use ERT. UARG members have gained more experience with ERT in recent months that has simply confirmed and elevated those objections. Use of 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. It also is subject to significant performance issues, including software crashes and shutdowns, inoperable features (like report generation), and inadequate identification of errors preventing data analysis. In short, even if EPA can justify a requirement to report performance test data electronically, EPA cannot justify requiring sources to use this program.

Response: See the preamble for discussion of the electronic reporting mechanism.

Commenter Name: Lee B. Zeugin
Commenter Affiliation: Utility Air Regulatory Group
Document Control Number: EPA-HQ-OAR-2002-0058-2880.1
Comment Excerpt Number: 63

Comment: UARG also has a number of legal concerns with EPA's proposal. First, EPA has made no effort in its proposal to identify the software it proposes to require, other than by name. If EPA finalized this rule, EPA could substitute virtually any version of this program, or even another program by the same name and attempt to mandate its use. For EPA to promulgate an enforceable software requirement, EPA must identify the software with sufficient specificity that it can be incorporated by reference into the rule. If EPA simply wants to require electronic reporting, 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.

Response: See the preamble for discussion of the electronic reporting mechanism.

Commenter Name: Lee B. Zeugin
Commenter Affiliation: Utility Air Regulatory Group
Document Control Number: EPA-HQ-OAR-2002-0058-2880.1
Comment Excerpt Number: 64

Comment: Contrary to 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 EPA's proposed rule. A brief comparison of the reporting requirements in Method 5 (40 C.F.R. Part 60, Appendix A, Method 5, § 11.2.2 and 11.2.4 -- "[r]eport the results to the nearest 0.1 mg") with EPA's description of ERT in its Electronic Reporting Users Guide Version 3.1, June 2009 (creating test plan, run data, test data, process data, etc.) illustrates this point. Similarly, EPA's proposed requirement in § 63.7550(h) to report "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. To comply with the Paperwork Reduction Act and its implementing regulations, 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 EPA review of those data. EPA has done none of that. If EPA intends to require reporting of more than the test results already required to be reported under the applicable EPA test methods, EPA must issue a supplemental proposal identifying and soliciting comment on the information it seeks to collect.

Response: See the preamble for discussion of the electronic reporting mechanism.

Commenter Name: Lee B. Zeugin
Commenter Affiliation: Utility Air Regulatory Group
Document Control Number: EPA-HQ-OAR-2002-0058-2880.1
Comment Excerpt Number: 65

Comment: Any electronic report used to satisfy federal reporting requirements also must meet the requirements of the Cross-Media Electronic Reporting Rule, codified at 40 C.F.R. Part 3, including the requirement that the document include a valid electronic signature, as defined in the rule. EPA has made no attempt to explain how ERT or WebFIRE meet this requirement. UARG also is concerned regarding the ability of ERT to satisfy other criteria 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. See., e.g., 40 C.F.R. § 3.2000(b)(5). In UARG's experience, ERT satisfies none of these criteria. Especially troublesome is the inability of the responsible official to prevent revision of the information in ERT at or after the point of submittal. EPA cannot require sources to submit data using a mechanism that does not satisfy its own requirements for such submissions. Promises by EPA that these issues will be addressed by the time reports must be submitted are not sufficient to satisfy EPA's obligations under the CAA to provide notice and opportunity for comment at the time of proposal.

Response: See the preamble for discussion of the electronic reporting mechanism.

Commenter Name: Lee B. Zeugin
Commenter Affiliation: Utility Air Regulatory Group
Document Control Number: EPA-HQ-OAR-2002-0058-2880.1
Comment Excerpt Number: 66

Comment: UARG does not agree with EPA's unsupported assertion that the information required to be submitted under ERT to WebFIRE will benefit EPA and sources by improving emission factors. EPA has yet to explain in any detail how the process of emission factor development from performance test data submitted to WebFIRE will work. In its comments on the ANPR, UARG expressed concerns about the process EPA described and objected to any attempts to mandate submission of reports before EPA had more completely explained its plans, completed any necessary rulemakings, and made operational its website. UARG reiterates those points here. EPA should not be promulgating requirements intended to support a larger program piecemeal before that program has been fully developed. See, e.g., UARG Petition for Reconsideration of Portions of Final Standards for Coal Preparation and Processing Plants, EPA-

HQ-OAR-2008-0260 (Dec 7,2009) at 8-9 (incorporated by reference).[33 EPA granted UARG's request for reconsideration of the ERT/WebFIRE reporting requirement in Part 60, Subpart Y on March 3, 2010.] EPA should reserve the question of mandatory reporting to WebFIRE until it has resolved the questions raised in the ANPR.

Response: See the preamble for discussion of the electronic reporting mechanism.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 227

Comment: EPA SHOULD REMOVE THE ERT RECORDKEEPING REQUIREMENTS. The requirement for ERT reporting should be removed. Industry had many problems submitting Industrial Boiler MACT and CISWI ICR data using the ERT, and there are still many problems with the tool based on experience that utilities and testing firms are having while entering Utility Boiler MACT ICR data into the tool. Use of this tool will add cost and burden to the already costly emissions testing requirements in this rule. The tool is not a replacement for a stack test report, but rather an additional reporting burden, as permitting agencies will still require a hard copy stack test report with all supporting documentation.

The following are examples of issues encountered with the ERT:

It is not intuitive and it is difficult to use.

It is not set up to handle data from multiple stacks from the same source being tested at the same time.

It only allows for one intermittent leak check during a test run. Many stacks have more than two ports so the ERT should be set up to handle those scenarios rather than having to add leak check volumes together to come up with a total.

It is not set up to handle mixed blend calibration gases, which are extremely common.

The import tool is inadequate, as it does not have enough rows for long runs and often imports data in the wrong order.

The tool is not set up to handle blank corrections

The tool is "buggy" and slow to respond.

The tool seems to only be designed to work under the most ideal of test scenarios, which is not always realistic. The EPA should ask for comments on the format and uploading tool from individuals that encounter actual real world scenarios for testing to incorporate into future editions.

Revisions to the ERT should have a revision number such that the users can make sure the version they are using is the most recent version available.

Response: See the preamble for discussion of the electronic reporting mechanism.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 229

Comment: Compliance tests are submitted to the state or local permitting agency for review and approval. At times, the agency provides comments to the regulated facility that adjusts the test results. In these cases, the information entered into the ERT at the time of the stack test would not match the final, state-approved emission test results. At a minimum, there needs to be a mechanism for the ERT data to be updated in these situations or a flag to indicate whether the report has been reviewed and approved by the permitting agency. Alternatively, EPA could require the permitting agency to enter the stack test results into the ERT once approved, rather than requiring facilities to enter the data.

Response: See the preamble for discussion of the electronic reporting mechanism.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 230

Comment: If use of the ERT is required, EPA needs to develop a comprehensive ERT Guidance Manual that provide complete instructions with examples for:

all entries including:

the various facility identification codes, and where to find them

instructions on handling of non-detects

calibration instructions

required attachments

the "external" spreadsheets" that are used to import certain data into the ERT

the "external spreadsheets" that are used for reporting test methods not currently supported by the ERT

Response: See the preamble for discussion of the electronic reporting mechanism.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 231

Comment: EPA should also develop an "outreach" or "training" program that provides instructions for specific source categories and related parameters. Such efforts need to be readily-available – via presentations at relevant conferences/seminars, as well as web-based sessions ("webinars").

Response: See the preamble for discussion of the electronic reporting mechanism.

Recordkeeping and Reporting: Streamlining NSPS

Commenter Name: Robert D. Morrison
Commenter Affiliation: Abbott Laboratories
Document Control Number: EPA-HQ-OAR-2002-0058-2764.1
Comment Excerpt Number: 16

Comment: Boiler size categories in the proposed rule should be consistent with categories promulgated in the Boiler NSPS. In most, if not all, cases where monitoring is specified for the Boiler MACT, subcategories are proposed as less than 100 MMBtu/hour, 100 MMBtu/hour or more, less than 250 MMBtu/hour, and 250 MMBtu/hour or more. In that way, the few units rated exactly at a monitoring applicability threshold are assigned to the larger and more stringent of the two categories.

On the other hand, applicability of the New Source Performance Standards (NSPS) for steam generating units (40 CFR 60, Subparts Db and Dc) are based on rated capacity less than or equal to 100 MMBtu/hour, greater than 100 and up to 250 MMBtu/hour, and greater than 250 MMBtu/hour. As new units are constructed, it will promote consistency for monitoring provisions of the Boiler MACT and Boiler NSPS if both regulations use the same boiler size categories. Since the NSPS applicability criteria are established and the Boiler MACT are not, it would seem more efficient to modify all Boiler MACT classifications on boiler firing rate to conform with the NSPS.

Response: EPA agrees that the size categories should match the NSPS and has made the change. In the final rule no distinction is made at the 100 mmBtu/hr capacity rating, but the 250 mmBtu/hr is still relevant for the PM CEMS requirement.

Commenter Name: David A. Buff
Commenter Affiliation: Golder Associates Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2801.1
Comment Excerpt Number: 45

Comment: FSI strongly supports the ability to take federally enforceable limits on materials/fuels combusted in order to no longer be subject to a particular set of rules. Boilers can be designed for combusting multiple fuels, including biomass and materials that may become solid waste under the Section 129 rules. In practice, boilers can burn an array of fuels/materials, depending on fuel value, cost, and other factors. Fuel switching can be an important practice at any larger industrial facility in order to remain competitive and minimize fuel costs. Managing fuels is also important in reducing fossil fuel usage, which promotes the nations? energy independence. Therefore, the ability to switch fuels/materials combusted should be allowed, provided the applicable rules are met. A “once in, always in” requirement is nonsensical, and would not provide any major benefits.

Response: Refer to DCN EPA-HQ-OAR-2002-0058-2837.1, excerpt 2 for a response to issues related to a combustors fuel mix and rule applicability.

Commenter Name: Pamela F. Faggert
Commenter Affiliation: Dominion
Document Control Number: EPA-HQ-OAR-2002-0058-2908.1
Comment Excerpt Number: 31

Comment: Proposed Section 7525 contains provisions that require the collection of valid emissions data from CEMS and COMS for all operating hours per respective averaging period. the requirement to have valid emissions data for all operating hours is not realistic. Other established monitoring regulations, such as Sections 48 and 49 of 40 CFR Part 60 Da, do not contain such requirements and establish minimum valid data collection requirements. EPA should amend the following Section 63.7525 provisions to provide consistency with Part 60.48 and 60.49 monitoring and reporting requirements:
Proposed Section 63.7525(b) requires PM CEMS, on boilers > 250 mmBtu/hr, to record every hour for a 24 hour block and the collection of valid emissions data for all operating hours per 30-day rolling average. Section 60.48Da(p) of Subpart Da provides the operator the option to use PM CEMS to determine compliance with the PM emission limit and specifies that at a minimum, valid CEMS hourly averages shall be obtained for 75 percent of all operating hours on a 30-day rolling average basis (which will increase to 90 percent beginning on January 1, 2012). EPA

should amend the provisions of proposed Section 63.7525(b) to be consistent with Part 60.48Da(p).
Proposed Section 63.7525(a) requires CO CEMS, on boilers > 100 mmBtu/hr, to record every hour for a 30-day rolling average. Subsection (a)(6) states that any period when data is not available would be a "deviation from the monitoring requirements." EPA should amend these provisions to make the requirements consistent with existing monitoring requirements under Part 60.49Da(f)(2) where 90% of the operating hours in the 30-day averaging period must be valid. Provisions should also be added that would allow alternative compliance options at the discretion of the administrator for unusual circumstances that make this unusually difficult, such as low operating time for the source.
Proposed Section 63.7525(c) requires COMS record every 10 seconds for a 6-minute rolling average. Subsection (c)(6) states that any period when data is not available would be a "deviation from the monitoring requirements." COMS requirements should be consistent with 60.48Da(o)(2).

Response: CO CEMS requirements have been removed from the final rule. Regarding comments on PM CEMS, we have modified the language from the proposed 24-hour block to a 30-day rolling average. We disagree with the commenter about applying the data availability used in Da to the PM CEMS data collection. The Agency has developed a better understanding of the need for continuous data collection since Da was published and the equipment and software have dramatically improved as shown by the acid rain program CEMS data availability success. The monitoring system must operate at all time the process is operating.

Commenter Name: G. Vinson Hellwig
Commenter Affiliation: Michigan Department of Natural Resources and Environment
Document Control Number: EPA-HQ-OAR-2002-0058-2837.1
Comment Excerpt Number: 2

Comment: The very existence of two proposals, Maximum Achievable Control Technology (MACT) for Boilers at Major Sources and the New Source Performance Standards (NSPS) for Commercial and Industrial Solid Waste Incinerators (CISWI), with different emission standards, possibly subject to revision based on comments and/or litigation, is an argument in favor of allowing the owner or operator of an affected source to change their status. In addition, there is also a proposed change under the Resource Conservation and Recovery Act (RCRA), "Identification of Non-Hazardous Secondary Materials that are Solid Waste," which is a complicating factor in the decision-making process for those affected by this rulemaking.

There are many uncertainties in the proposals, including what materials may be categorized as non-hazardous solid wastes for the purposes of combustion. The RCRA determination is not to be based on the health and environmental impacts of controlled emissions from the combustion unit, but rather on a definition of what is a waste (and by inference, what is a fuel). The emission limits in the boiler MACT and the NSPS for CISWI vary by subcategory within each proposed rule. For some emissions, it may be to the facility’s benefit to be classified as an incinerator, and for others as a boiler. Faced with these complexities, the owners and operators of boilers and process heaters must be given the opportunity to evaluate the environmental and economic effects of the variety of possible choices and either opt-in or opt-out of regulation under one or the other of the proposed rules.

There are many existing facilities subject to the proposed rule in our state. Some of these have been legally permitted to burn a variety of alternative fuels for many years. The DNRE Air Quality Division’s enforcement records show that these facilities have not caused emissions that harmed the public health and natural resources. The proposed rule, "NESHAP for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters," will change the legal status of some of these facilities without any modification on their part. Based on the complexities associated with the existence of the several applicable proposed rules, we encourage EPA to allow the affected sources the flexibility to determine and to revise their permits and operational status.

Response: Sources can change their fuel mix to establish which rule they are subject to. The requirements are presented in the rules.

Compliance

Fuel Switching Compliance

Commenter Name: John Williams
Commenter Affiliation: Maine Pulp and Paper Association
Document Control Number: EPA-HQ-OAR-2002-0058-1913.1
Comment Excerpt Number: 10

Comment: Biomass Fuel Testing. The requirements in the rule for biomass fuel testing appear to be extremely onerous. Testing each time a new fuel supply is used can cost tens of thousands of dollars. In any given year, a mill might have 40-50 different fuel suppliers – wood is wood. Also, as written, the fuel testing will potentially result in unwarranted determinations of non-compliance due solely to normal variability of Hg, dioxin and HCl in wood fuels and/or laboratory analytical quantification limits on any given day.

Response: See response to comment EPA-HQ-OAR-2002-0058-2805.1, excerpt 8 for the definition of fuel type as it relates to biomass. According to the definition of fuel type, a change in fuel supplier in and of itself does not necessitate retesting.

Commenter Name: Michael Palazzolo
Commenter Affiliation: Alcoa Inc

Document Control Number: EPA-HQ-OAR-2002-0058-2967.1
Comment Excerpt Number: 12

Comment: Proposed §63.7530 would require the owner or operator to establish maximum fuel pollutant input levels for chlorine, mercury and/or total selected metals based on fuel composition during compliance testing. This requirement is not workable because the facility may not be able to obtain or process the "worst case" fuel during compliance testing to maximize the fuel pollutant content. Pollutant content will vary in available fuels, and a requirement to conduct additional testing to reset maximum fuel pollutant input levels for available fuels will be very time consuming and expensive and is unnecessary for units capable of operating below the applicable emission standard. Alcoa recommends that EPA allow additional flexibility for establishing the maximum fuel pollutant input levels by considering both pollutant input levels during the compliance test and the measured emission rate relative to the standard. For example, the tested input level and emissions could be prorated to a level equivalent to 90% of the emission standard to allow operating flexibility while still ensuring continuous compliance with the standard.

Response: See response to comment EPA-HQ-OAR-2002-0058-3213.1, excerpt 126 for flexibility in exceeding the maximum fuel input.

Commenter Name: Steven M. Maruszewski
Commenter Affiliation: The Pennsylvania State University
Document Control Number: EPA-HQ-OAR-2002-0058-2729.1
Comment Excerpt Number: 15

Comment: Fuel Analysis Testing - §63.7521(c)(1)(ii)
As stated, composite fuel samples will be collected during the compliance tests. This procedure will not accurately account for the variability of the various constituents in the coal. Specifically, the concentrations of chlorine and mercury tend to be quite variable. EPA's guidance document for the 114 Phase II ICR acknowledged and addressed this concern for variability by requiring 10 samples over a 30 day period. The University suggests that this same procedure should be used when collecting the annual compliance samples.

Response: The commenter notes that the ICR testing program required 10 samples collected over 30 days. The rule requires at least three stopped belt samples (or ASTM sampling) collected over the period of a performance test (i.e., a few hours). If a source believes that the number of samples required in 60.7521 is not representative of the mercury or chlorine levels in their given fuel, they may propose in their site-specific fuel analysis plan that more samples be taken. In an effort to minimize burden while accounting for fuel variability, EPA has established a minimum of three stopped belt samples, and five truck or fuel pile samples.

Commenter Name: Arthur N. Marin

Commenter Affiliation: NESCAUM
Document Control Number: EPA-HQ-OAR-2002-0058-2893.1
Comment Excerpt Number: 27

Comment: EPA has not provided a clear definition as to what constitutes new fuel. Unlike liquid fuels and coal, most biomass fuels are inherently inhomogeneous. For example, does a wood chip facility need to test for Hg and HCl for every new load or new supplier of fuel? As proposed, the language is unclear as to when a facility must conduct a test to show compliance with emission limits when fuel switching occurs, or the frequency of this testing. NESCAUM recommends that EPA clarify this rule to require testing upon use of a new fuel. Additionally, NESCAUM recommends that EPA not require facilities burning biomass to conduct fuel testing on each new load of biomass nor when a facility switches biomass fuel suppliers.

Response: See response to comment EPA-HQ-OAR-2002-0058-2805.1, excerpt 8 for clarification of fuel type with respect to biomass fuels.

Commenter Name: Britt S. Fleming
Commenter Affiliation: Auto Group
Document Control Number: EPA-HQ-OAR-2002-0058-2775.1
Comment Excerpt Number: 43

Comment: Proposed § 63.7520(c), which requires testing using the highest content of chlorine and mercury while testing at the maximum normal operating load. It is not possible for sources using landfill gas to change the chlorine and mercury content for purposes of a performance stack test. Furthermore, since these types of boilers do not typically operate at maximum load, maximum normal operating load would need to be replaced with maximum available load during the performance test in order to properly account for these units.

Response: The facility is responsible for demonstrating that they are able to continuously comply with the emissions limits when operating under expected operating conditions. If a stack test does not represent the range of combined process and control measure conditions under which the facility expects to operate, the delegated agency may determine that retesting is warranted.

Commenter Name: Stephen R. Gossett
Commenter Affiliation: Eastman Chemical Company
Document Control Number: EPA-HQ-OAR-2002-0058-3137.1
Comment Excerpt Number: 50

Comment: The proposed compliance demonstration and monitoring requirements for fuel-dependent HAP emission limits are unworkable and do not provide compliance certainty for complex sites using fuels with variable fuel dependent HAPs.

EPA has proposed that sources demonstrate initial and on-going compliance with the mercury and hydrogen chloride emission standards by establishing the maximum HAP content (mercury or chlorine) in each fuel type (“coal” is a fuel type) from a minimum of just three composite samples and calculating the 90th percentile confidence level (P90) from these three samples. In a case where the source must rely on removal efficiency of the boiler system and/or air pollution control system to comply with the emission standard, the P90must be determined from three samples taken during the 3-run performance test. Thereafter, the EPA proposal requires the source to maintain records of the amount of each fuel type burned and to calculate P90 each time a new fuel type is burned. If P90 for the new fuel type is higher than the previous determination, a new performance test must be conducted (unless the source is complying with fuel analysis alone).

Given our knowledge of the variability of a fuel such as bituminous coal, use of this simplistic compliance procedure raises concerns regarding our compliance obligations. Under Title V Operating Permits, sources are required to submit annual certifications of compliance. Also, the issue of Credible Evidence is of concern if we have knowledge that coal we are supplied does not always have chlorine or mercury levels below the respective P90 values.

The wording of the proposed rule would require redetermination of P90 only when the fuel type is changed. However, the preamble (page 32014) states that the recalculation must be done when “you plan to burn a new fuel, a fuel from new mixture, or a new supplier’s fuel that differs from what was burned in the initial performance tests.” This would be unworkable for a complex facility such as Eastman that has as many as 20 different suppliers of a highly variable fuel (coal) which vary from year to year. This requirement would likely interfere with our business need to purchase coal from the spot market, particularly during periods when the coal market is tight. Also, a three composite sample taken on the same day is not likely to represent the long-term variability of even a single supplier, much less the variability of a broad fuel “type” such as coal.

Response: EPA has provided several provisions including multiple composite samples, annual averaging (for determining compliance using fuel analyses) or three test runs for stack tests, coupled with requiring a 90th percentile confidence level, to address variability in a given fuel supply. Sources must develop and submit a site-specific fuel analysis plan which may specify the use of a greater number of composite samples as necessary to address fuel variability, and must conduct performance tests using fuel that has the highest expected levels of chlorine and mercury. The commentor is concerned, in part, that the requirement to perform fuel analyses when they plan to burn a new fuel, a fuel from new mixture, or a new supplier’s fuel that differs from what was burned in the initial performance tests will interfere with their practice of using many different fuel suppliers. The regulation does not, however, require that fuel analyses be performed with each new fuel supplier, if the fuel supplied does not differ from the type of fuel burned in the initial performance test.

Commenter Name: Stephen R. Gossett
Commenter Affiliation: Eastman Chemical Company

Document Control Number: EPA-HQ-OAR-2002-0058-3137.1
Comment Excerpt Number: 51

Comment: In order to have a workable and enforceable compliance program that adequately assures continuous compliance with the emission standards, we suggest a different monitoring program be allowed as an option. Here, a source would develop a fuel sampling plan customized for its specific fuel types. For example, for Eastman's coal supply, we could sample (using standard ASTM sampling methods) and analyze each shipment of coal for heating value, chlorine and/or mercury content, and store that data in a spreadsheet along with the quantity of coal in the shipment (e.g. number of cars). The source can then calculate the weighted average lb/mmBtu feed rate of chlorine and/or mercury fed to a given boiler (or set of boilers that are served by a common coal feed system) on a rolling average basis. On a monthly basis, a compliance determination that the 12 moving average chlorine and/or mercury feed rate is less than the allowable feed rate would be made. For a unit not relying on the system control efficiency, that allowable feed rate would be equal to the emission standard, expressed as lb/mmBtu. For a unit that does rely on system control efficiency, the source should be allowed to establish an allowable feed rate based on a successful performance test by extrapolating from the actual feed rate and actual emission rate measured during the test.

This approach would follow closely with the compliance program used to comply with the Hazardous Waste Combustor MACT (40 CFR 63 Subpart EEE). In this rule, each source develops and implements a Feedstream Analysis Plan to adequately characterize the materials to be incinerated and then track the feed rates of parameters such as chlorine, metals, and ash to ensure they stay below the allowable feed rates established from a Comprehensive Performance Test. We note particularly that Subpart EEE specifies up to an annual rolling average for mercury for liquid fuel boilers (see 40 CFR 63.1209(l)(1)(ii)).

In order to facilitate incorporation of this compliance option, we have included some suggested regulatory language:

§63.7530 (b) If you demonstrate compliance through performance stack testing, you must establish each site-specific operating limit in Table 2 to this subpart that applies to you according to the requirements in §63.7520, Table 7 to this subpart, and paragraph (c)(4) (b)(3) of this section, as applicable. You must also conduct fuel analyses according to §63.7521 and establish maximum fuel pollutant input levels according to paragraphs (c)(b)(1) through (3) (2)or (3) of this section, as applicable.
****
(3) Extrapolation of feedrate levels. In lieu of establishing mercury and/or chlorine feedrate limits as specified in paragraphs (b)(1) through (2) of this section, you may request as part of the performance test plan under §§63.7(b) and (c) and §§63.7520(a) to use the mercury and/or chlorine feedrates and associated emission rates (HCl in the case of chlorine) during the comprehensive performance test to extrapolate to higher allowable feedrate limits and emission rates. The mercury and/or chlorine feedrates shall be expressed as pounds per million Btu heat input. The extrapolation methodology will be reviewed and approved, as warranted, by the Administrator. The review will consider in particular whether:

(A) Performance test mercury and/or chlorine feedrates are appropriate (i.e., whether feedrates are at least at normal levels; depending on the heterogeneity of the fuel, whether some level of spiking would be appropriate; and whether the physical form and species of spiked material is appropriate); and

(B) Whether the extrapolated feedrates you request are warranted considering historical mercury and/or chlorine feedrate data.

§63.7530 (c) If you elect to demonstrate compliance with an applicable emission limit through fuel analysis, you must conduct fuel analyses either according to §63.7521 and follow the procedures in paragraphs (c)(1) through (5) (4) of this section or according to the procedures in §63.7540(c) .

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§63.7540(c) In lieu of demonstrating initial compliance with the applicable HCl and/or mercury emission limit following the method in §63.7530 and in lieu of demonstrating continuous compliance with the applicable HCl and/or mercury emission limit following

Eastman Boiler MACT Comments Page 29 of 45 the method in paragraph (a) of this section, you may follow the method specified in paragraphs (c)(1) through (2) of this section.

(1)Site-specific fuel analysis plan. You must follow the requirements of §63.7521(b). In addition, you must specify in the plan the frequency with which you will determine mercury and/or chlorine content in each fuel.

(2) Compliance with mercury and/or chlorine feedrate limits. To comply with the applicable feedrate limits of §63.7530, you must monitor and record mercury and/or chlorine feedrates as follows:

(i) Determine and record the value of the parameter for each fuel following the site-specific fuel analysis plan developed following paragraph (c)(1) of this section.

(ii) Determine and record the mass or volume flowrate of each fuel for each operating hour using a continuous monitoring system. If you determine flowrate of a fuel by volume, you must determine and record the density of the fuel by sampling and analysis (unless you report the constituent concentration in units of weight per unit volume (e.g., mg/l)); and

(iii) Calculate and record the mercury and/or chlorine feedrate for each operating hour using Equation A.

o o ee e) i i)) i i) Equation A

Where:

Hourly Pollutant Feedrate (HPF) = mercury or chlorine feedrate to the boiler or process heater in units of pounds per million Btu heat input for each operating hour.

Ci = percent by weight mercury or chlorine concentration for fuel type, i, for the operating hour as determined using the fuel analysis plan developed according to paragraph (c)(1) of this section.

Mi = mass of fuel type, i, in units of pounds for the operating hour as determined according to paragraph (c)(2)(ii) of this section.

HVi = heating value for fuel type, i, in units of Btu per pound for the operating hour as determined using the fuel analysis plan developed according to paragraph (c)(1) of this section.

n = Number of different fuel types burned in your boiler or process heater during the operating hour.

(iv) At the end of each calendar month, calculate and record the twelve

month rolling average mercury and/or the HCl feedrate for your boiler or process heater using Equation B.

we e o o i e e o ee e)) Equation B
Where:
Hourly Pollutant Feedrate (HPF) = mercury or chlorine feedrate to the boiler or process heater in units of pounds per million Btu heat input for each operating hour as determined according to paragraph (c)(2)(iii) of this section.
n = number of operating hours during the past 12 months.

Response: 40 CFR § 60.8(b) provides authority for alternative performance testing under NSPS . This authority can be used to develop alternative compliance strategies as the commenter requests. In like measure, a facility owner or operator may seek relief from retesting under these authorities. The Agency would review the proposed alternatives on a case by case basis, to include the reduction in testing frequency associated with low hazard fuels.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 121

Comment: AF&PA supports the concept of allowing sources burning fuels with low mercury or chlorine content to avoid installing expensive, unneeded control equipment. However, we find the testing, monitoring, record-keeping and reporting requirements to be not only excessively burdensome, but simply unworkable for boilers burning wood, wood residuals, other biomass fuels, or a combination of solid fuels – practices that are very common in our industry. AF&PA's members operate multi-fuel, or combination, boilers that may burn four or more fuels during a given year, month, or week, including, but not limited to, wood, bark, other wood residuals (chips, knots, or sawdust, for example), panel plant trim, sludge, tire-derived fuel, coal, oil, and natural gas. Many of these boilers rely on wood, bark, and wood residuals as their primary fuel. Defining worst-case fuels and requiring mills to retest their multi-fuel boiler fuel mixes whenever they change suppliers will present enormous, and perhaps insurmountable, logistical problems. Mills relying heavily on wood, bark, or wood residuals may receive shipments from as many as 100 suppliers/woodlots a month, raising the likelihood of constant fuel sampling, retesting and, quite possibly, frequent performance testing. Some mills are receiving logs from foreign locations. AF&PA believes EPA's proposed testing, monitoring, record-keeping and reporting approach is unworkable for these types of units and EPA should not require mills to analyze biomass fuels obtained from each and every supplier.

Response: See response to comment EPA-HQ-OAR-2002-0058-2805.1, excerpt 8 for the definition of fuel type as it relates to biomass. According to the definition of fuel type, a change in fuel supplier in and of itself does not necessitate retesting.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)

Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 126

Comment: While this compliance approach may be easy to manage for some sources, especially ones with very stable fuel supply and usage, it may be very cumbersome and burdensome for other sources with variable fuel suppliers and fuel mixes. This approach involves a great deal of recordkeeping and potentially subjects the source to frequent testing requirements if fuel content varies, regardless of the margin of compliance shown during the initial performance test. Under the proposed rule, even if a unit is operating at 50 percent of the applicable emission limit, the facility would be required to re-test if the fuel chloride input increases 1 percent over the level achieved during the initial performance test.

A more appropriate approach is to allow the source to set operating parameters at levels that generate emissions at the emission limits established in the rule. This is the only approach which meets the requirements of the Act, since it is the only approach that does not impose a beyond the floor limit which has not been justified per the requirements of 112(d). Under this approach, the source would simply do the performance test using its normal fuel mix, determine operating conditions that show compliance and then adjust those conditions, using engineering calculations to assure it would meet the emissions standards established in Table 1 or 2. If the initial performance test shows emissions at 50 percent of the standard at a particular mercury or chloride fuel input, the fuel input limits should be set at a level higher than the performance test values, taking into account control device operating parameters as appropriate. This approach would be environmentally beneficial and would greatly reduce burdens. It is the only practical way to establish fuel input operating limits.

Compliance could also be demonstrated through the use of fuel purchase specifications. Sources would determine from the performance test a maximum fuel pollutant concentration at which the emissions limitations are achieved. For instance, the performance test may demonstrate that fuels containing chlorine in concentrations less than x Ib CI/MMBtu allow the source to comply with emissions limitations. A facility should be allowed to extrapolate an allowable fuel input based on a comparison of performance test conditions to the applicable emission limit. The source would then set a fuel specification of x Ib CI/MMBtu and would be allowed to burn any fuel of the same general type (e.g., solid, liquid, or gas) as long as it met this specification. Sources could require that the fuel supplier provide periodic certification that the fuel meets the specification, based on analysis, or could establish an internal sampling and analysis program for that purpose. In any case, where common fuels are utilized in more than one unit, common fuel quality data would be maintained and considered applicable to all such units. Continuous compliance could also be demonstrated through ongoing fuel analysis.

As an example, sources would (1) establish a fuel input limit (e.g., Ib Cl/MMBtu) based on the compliance test as described in the proposal (with an allowance for extrapolation); (2) periodically sample and analyze each fuel for constituent concentration and heating value according to a specified sampling and analysis plan; (3) monitor the daily usage of each fuel; (4) calculate the average total daily constituent input (lb/MMBTU) accounting for all fuels fed; and (5) demonstrate that the average daily constituent input rate averaged over each month of operation does not exceed the operating limit. This option would afford the source the opportunity to vary fuel mixes, while still insuring that protective operating limits are met.

Given the wide variety of sources impacted by this proposal, it is reasonable to provide flexibility in how sources demonstrate compliance, as long as clearly-defined compliance objectives are met. AF&PA requests that EPA include the compliance approaches discussed above in the final rule as allowable optional compliance strategies. We are willing to work with the agency to further refine these strategies. Additionally, AF&PA requests that the final rule include an allowance for a source to use, with prior Agency approval, other compliance strategies that may be more appropriate on a site-specific basis.

Response: 40 CFR § 60.8(b) provides authority for alternative performance testing under NSPS . This authority can be used to develop alternative compliance strategies as the commenter requests. In like measure, a facility owner or operator may seek relief from retesting under these authorities. The Agency would review the proposed alternatives on a case by case basis, to include the reduction in testing frequency associated with low hazard fuels. For example, sources can also submit a fuel monitoring alternative for approval in their fuel monitoring plan to establish an operating limit based on extrapolation from the fuel content used during the initial compliance test and the applicable emission limit for that source.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 275

Comment: A regulatory mandate to switch from solid fuels to natural gas, while aimed at reducing emissions from coal, would have the unintended effect of substantially curtailing the viability of burning biomass fuels. Forest product mill industrial boilers often co-fire coal with biomass residuals (e.g., bark, wood chips, rejected fiber, knots, and/or non-recyclable fiber) and get more than 60% of their energy needs from biomass-based fuels. Smaller wood products boilers may burn only biomass residual materials. However, as EPA has recognized, boilers configured for a certain physical phase (i.e,. solid, liquid, or gas) fuel in most cases would not be able to operate using a different-phase fuel.
The limitation the proposed rules would engender on the ability of facilities to use biomass for fuel is at odds with other environmental goals. From pollution prevention, climate change, and fossil resource conservation perspectives, as well as to ensure full utilization of biomass materials, the burning of wood products residuals (that have no other commercial utility) should be encouraged as good public policy. Doing so utilizes wood residuals for their fuel value, conserving valuable landfill space and avoiding unnecessary fossil fuel consumption. Moreover, an executive order entitled “Developing and Promoting Biobased Products and Bioenergy” notes the significant environmental benefits of enhanced utilization of biomass, including using biomass for energy. See Executive Order 13134, 64 Fed. Reg. 44638 (August 16, 1999). These benefits include: “the potential to reduce our Nation’s dependence on foreign oil, improve air quality, water quality, and flood control, decrease erosion, and help minimize net production of

greenhouse gases." Id. at 44639. Significantly, unlike coal and natural gas, biomass is not a fossil fuel, so that energy generated from biomass does not result in a net release of greenhouse gases to the atmosphere. In light of the detrimental effect of fuel switching on biomass fuel, EPA properly rejected this option in setting the MACT floors.

Response: EPA thanks the commenter for their input and has retained is position of rejecting fuel switching as a MACT floor option.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 297

Comment: Fuel sampling should not be required for each new fuel supplier.
Pulp and paper mills burning biomass have a large number of biomass suppliers and hundreds of trucks deliver biomass fuel to the facility in a day. The rule should simply require a representative sample of biomass from the fuel pile. This comment is also relevant to facilities burning coal. The rule should require one sample per coal type (e.g., bituminous versus sub-bituminous) not one sample per coal supplier.

Response: Fuel sampling when you switch fuel suppliers is only required if that supplier's fuel is a different fuel type or mixture than what was burned during the performance test. EPA believes that requiring a fuel analysis for each new fuel is reasonable and necessary for assuring compliance with the standards. The fuel sampling methodology in the proposed rule at 63.7521 specifies the means for obtaining a representative sample.

Commenter Name: Randall D. Quintrell
Commenter Affiliation: Georgia Paper and Forest Products Association, GPFPA
Document Control Number: EPA-HQ-OAR-2002-0058-2905
Comment Excerpt Number: 18

Comment: GP&FPA operates a variety of boiler types and have many combination fuel or multi-fuel boilers. The performance testing requirements in the proposed Rule for a multi-fuel boiler are somewhat unclear at best and unachievable at worst. For one, the testing provisions in 40 CFR 63.7520(c) use undefined terms that create confusion. These include: "maximum normal operating load"; and "mixture of fuels that has the highest content of chlorine and mercury".

For example, one mill operates an existing unit that would be classified as a "designed to burn biomass" unit because on an annual basis, the heat input capacity of coal is less than 10%. However, on a short-term basis, the unit is capable of combusting 100% coal. As the coal potentially has the highest levels of HC1 and Hg, would the mill be required to test this unit at 100% coal or other very high atypical usage rate and compare those emissions to the limitations for boilers designed to burn biomass, which is its official classification? With such extended test runs, this would be extremely expensive even if a stable fuel supply could be maintained for such a duration at all. Also the biomass limits for Hg and HC1 would be impossible to meet at high rates of coal firing - that is why there are separate subcategories in the first place. We believe that EPA's intent for such units is for them to test using a fuel mix that is representative of typical operations, but that is not clearly specified in the proposal and the language could be interpreted otherwise. The final Rule needs to address multi-fuel boiler situations such as this both from an emissions limitation standpoint and from a testing standpoint. EPA must revise the testing criteria discussed above to give more consideration to the reality of the challenges involved in conducting performance tests on multi-fuel boilers and provide more specific input as to the expectations for such performance testing.

Response: See response to comment EPA-HQ-OAR-2002-0058-2723.1, excerpt 73 for clarified intent.

Commenter Name: David A. Buff
Commenter Affiliation: Golder Associates Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2801.1
Comment Excerpt Number: 24

Comment: It is not possible to set maximum fuel inlet operating limits based on a single annual test, particularly for fuels which naturally vary over the course of a year. An annual test that is "representative" of the fuel should be adequate, and not require setting fuel inlet operating limits. This is particularly for biomass-fired sources, where the fuel content will not vary greatly over a year.

Response: The maximum input levels for chlorine and mercury determined from equations 7 & 8, respectively, are not operating limits but are rather levels which can be used to provide an indication of whether a fuel switch may affect the source's compliance status.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 25

Comment: Gas- and liquid-fired boilers and process heaters can often change fuels with little or no equipment modification. For instance, units with both liquid and gas capability can move from gas to liquid with simple fuel realignments. Units that fire gas can move between the Gas 1 and Gas 2 subcategories simply because site fuels are mixed differently or because operating rates or fuel gas production changes result in changes to the site fuel gas/natural gas balance. For this reason, among others, we believe there should only be one gas subcategory, and we discuss that recommendation in section IV.D of these comments.

If two gas subcategories are maintained and the proposal work practice and emission limit proposals are adopted, the common situation of a unit moving from the Gas 1 subcategory to the Gas 2 subcategory and the reverse must be addressed. Additionally, the definitions of these two subcategories must be made consistent. We recommend that if a unit moves between Gas 1 and Gas 2, the unit have up to three years to transition from the Gas 1 requirements to the Gas 2 requirements. This is necessary because these transitions are often not planned but occur because of changes in available gases due to varying operating rates of particular processes, addition of new steam or fuel producers or consumers or changes in feedstocks that yield different amounts of fuel gas from a particular process. Thus, if a Gas 1 unit fires more than 10% Gas 2 in a calendar year, it must have three years to re-permit [Footnote: Permitting is an issue because Title V permits will have to include the requirements from subpart DDDD for the particular subcategory that applies to that boiler or process heater.] the unit and to meet the extensive Gas 2 requirements. If a Gas 2 unit fires more than 90% Gas 1 in a year it should have whatever time it takes to re-permit the unit to transition to the Gas 1 requirements.

The movement of a unit from a gas subcategory to the liquid subcategory and vice versa must also be addressed. This can happen because of changes in fuel economics but, more typically, would happen because liquid firing exceeds 10% in a calendar year for a particular unit because of gas supply problems or extended fuel gas imbalances. In this case, we also request three years be allowed for the unit to re-permit and to comply with the new set of requirements.

The situation of a boiler or process unit opting to change from Gas 2 or liquid fuel to Gas 1 prior to the compliance date of this rule also needs to be addressed, but that situation would only need additional compliance time if emission limits are imposed for Gas 1.

Recommendation: Allow three years for compliance for units that move from the Gas 1 subcategory to the Gas 2 subcategory or units that move from a gas subcategory to the liquid subcategory.

Response: &&&
ISSUES TO ADDRESS: 1. WILL WE BE REVISING THE GAS 1 & 2 SUBCATEGORIES; 2. HOW MUCH TIME WILL BE GRANTED FOR SOURCES TO COME INTO COMPLIANCE WITH A NEW SUBCATEGORY; 3. CAN COMPLIANCE BE DELAYED UNTIL REPERMITTING UNDER TITLE V

PROPOSED POSITION FOR 2 & 3. THIS LANGUAGE NEEDS TO BE FINESSED BY OAQPS AND OGC -- THIS IS JUST TO GET US GOING:

Sources may switch fuels and therefore switch subcategories, however it must be done in a way that does not create delays in compliance, impede our ability to determine compliance with the initially /previously applicable standards, or allow for large periods of time during which the compliance status of the facility is unknown. As a threshold matter, since several compliance options for the rule allow annual averaging, sources may not switch between fuel subcategories more frequently than once per year.

The Clean Air Act requires that EPA establish a compliance date or dates for each category or subcategory of existing sources which shall provide for compliance in no event later than three years after the effective date of the standard. As such, EPA is not granting an additional three years each time a source decides to switch fuels and becomes subject to a different subcategory. EPA expects that sources that wish to switch fuels will plan for the fuel switch and will be in compliance as of the date that the source becomes subject to the new subcategory. The only compliance extension available would be a case-by-case determination as to whether up to one additional year is necessary for the installation of controls, as allowed in CAA Section 112(i)(3)(B). NEED TO CHECK WITH OGC IF THIS IS EVEN AVAILABLE IF THE RULE HAS ALREADY BEEN EFFECTIVE FOR 4 YEARS.

Extending the compliance deadline to allow additional time for repermitting is not appropriate since the permit is designed to reflect the applicable requirements of the underlying regulations, not to delay effectiveness of applicable requirements and pollution controls.

The final rule clarifies that sources must remain in a given subcategory for a period of at least 12 months after the initial compliance test that demonstartes compliance with all the standards. Initial testing to demonstrate compliance with a new subcategory after a fuel switch must be completed within 90 days of the date upon which the source has identified via notification to the Agency that a subcategory switch will occur. Since the source will have already been operational and subject to the Boiler MACT for over a year, EPA believes that 90 days is sufficient time for the facility to familiarize itself with its new combustion practices and controls, schedule the test, and provide the 60 days advance notification.

Commenter Name: Donald R. Schregardus
Commenter Affiliation: Department of Defense
Document Control Number: EPA-HQ-OAR-2002-0058-2763.1
Comment Excerpt Number: 26

Comment: §63.7540(a)(2) states that records of type and amount of fuel are required to demonstrate that the fuel has lower fuel input for mercury and HC1 than the maximum values calculated during the last performance tests "(if you demonstrated compliance through performance stack testing)." Does this apply only to sources that demonstrated compliance through stack testing without using control devices or does it apply to everyone stack testing irrespective of control devices?

Response: The requirement in 63.7540(a)(2) to keep records on the type and amount of fuels burned applies to all affected sources irrespective of how compliance is demonstrated and achieved.

Commenter Name: Donald R. Schregardus
Commenter Affiliation: Department of Defense
Document Control Number: EPA-HQ-OAR-2002-0058-2763.1
Comment Excerpt Number: 27

Comment: §63.7530(b) requires calculation of the maximum chlorine input level using equation seven (7) and the maximum mercury input level using equation eight (8) "if you demonstrate compliance through performance stack testing." This maximum fuel input level calculation is based on the average values of mercury and chlorine derived from fuel samples taken during the stack test. §63.7540(a)(2) requires continuous compliance with these maximum fuel input levels. Because these maximums levels are calculated from average values, it is impossible to continuously assure compliance with this provision because the formulas do not take into account the normal variability of the mercury and chlorine content of the fuel. Does the provision to calculate maximum fuel input levels only apply to those sources that burn more than one type of fuel simultaneously?

Response: The input levels for chlorine and mercury determined from equations 7 & 8, respectively, are not operating limits but are rather levels which can be used to provide an indication of whether a change in fuels may have affected the source's compliance status. The provision to calculate maximum fuel input levels applies to any source that opts to determine compliance with the HCl and mercury limits using stack testing.

Commenter Name: Donald R. Schregardus
Commenter Affiliation: Department of Defense
Document Control Number: EPA-HQ-OAR-2002-0058-2763.1
Comment Excerpt Number: 28

Comment: One DoD facility burns only coal in their solid fuel boilers. Are they required to conduct monthly fuel analysis for mercury and chlorine content to demonstrate continuous compliance with a maximum chlorine content level determined by equation 7 and a maximum mercury content level determined with equation 8? If so, it is impossible to continuously comply with this requirement because it is impossible for a coal supplier to guarantee that all coal supplied from a coal seam will be less than the average value of mercury and chlorine content from that same seam. Does EPA expect sources to test with coal having ultra-high levels of mercury and chlorine? How does EPA propose locating special test coal? Does EPA endorse the use of special test coal for compliance demonstrations? How can EPA justify establishing a maximum value limitation from the average of the fuel group when the fuel group itself is what is normally burned?

Response: The chlorine and mercury input levels are not limitations, but are rather levels used to evaluate whether a fuel switch may affect the source's ability to comply with the standard. For sources that opt to demonstrate compliance using stack tests instead of fuel analysis, you must recalculate the maximum chlorine and mercury input if you plan to burn a new fuel, a fuel from a new mixture, or a new supplier's fuel that differs from what was burned during the initial performance tests based on supplier data or own fuel analysis using the methodology specified in Table 6 of this proposed rule. Although the preamble to the rule explained this process, we are making some corrections and clarifications to § 63.7530(b) and § 63.7540(a)(4) to reference the method for determining chlorine and mercury input, and to correct cross-references and the equation numbers for determining the maximum input levels (6 and 7).

EPA expects that sources will test, consistent with 63.7520(c), under conditions that will demonstrate the source's ability to continuously comply with the emissions limits when operating under expected operating conditions. If a stack test does not represent the range of combined process and control measure conditions under which the facility expects to operate, the delegated agency may determine that retesting is warranted.
See response to comment EPA-HQ-OAR-2002-0058-2763.1, excerpt 28 for discussion of maximum chlorine and mercury input.

Commenter Name: Donald R. Schregardus
Commenter Affiliation: Department of Defense
Document Control Number: EPA-HQ-OAR-2002-0058-2763.1
Comment Excerpt Number: 29

Comment: DoD facility stack test example maximum content calculation: Stack Test #1 Fuel Analysis Content Results
Run #1 Hg = 2.14 x 10-61b/MMBtu Cl = 0.128 lb/MMBtu
Run #2 Hg = 6.52 x 10-61b/MMBtu Cl = 0.105 lb/MMBtu
Run #3 Hg = 1.46 x 10-6 lb/MMBtu Cl = 0.139 lb/MMBtu
Average and Max. Content Limitation Hg = 3.37 x 10-6 lb/MMBtu CI = 0.124 lb/MMBtu

Stack Test #2 Fuel Analysis Content Results
Run #1 Hg = 3.57 x 10.6 lb/MMBtu Cl = 0.106 lb/MMBtu
Run #2 Hg = 1.42 x 10-6 lb/MMBtu Cl = 0.114 lb/MMBtu
Run #3 Hg = 2.13 x 10-6 lb/MMBtu Cl = 0.106 lb/MMBtu
Average and Max. Content Limitation Hg = 2.37 x 10-6 lb/MMBtu Cl = 0.109 lb/MMBtu

Depending on which maximum content limitation would be established from stack testing coal analysis results, this facility expects to be out of compliance with both the maximum mercury and maximum chlorine content limitations between 33 and 66 percent of the time if an individual test run were representative of one month's coal analysis data. Thus, the requirement to use equations 7 and 8 as written is impossible to comply with under normal boiler operations and typical fuel analysis results.

Response: The input levels for chlorine and mercury determined from equations 7 & 8, respectively, are not operating limits but are rather levels which can be used to provide an indication of whether a change in fuels may have affected the source's compliance status. The standard sets operating limits for control device operating parameters which must be complied with on a continuous basis.

Commenter Name: David A. Buff
Commenter Affiliation: Golder Associates Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2801.1
Comment Excerpt Number: 54

Comment: Facilities should not be required to perform fuel analysis for each supplier – there may be a number of suppliers for coal and biomass. Biomass in particular does not vary greatly, such that individual supplier analysis is not justified.

For biomass, the fuel input limitation should not be based solely on the initial performance test, because natural variations in the biomass may cause later deviations from the limit. Sources should be allowed to demonstrate the control efficiency (based on measuring fuel input and stack emissions) during the initial performance test, and utilize this efficiency to determine the maximum fuel input limits for chlorine, mercury and total selected metals (assuming TSM is included in the final rule) allowable in order not to exceed the emission limits.

Response: See response to comment EPA-HQ-OAR-2002-0058-2805.1, excerpt 8 for the definition of fuel type as it relates to biomass. According to the definition of fuel type, a change in fuel supplier in and of itself does not necessitate retesting. See response to comment EPA-HQ-OAR-2002-0058-3213.1, excerpt 126 for flexibility in exceeding the maximum fuel input.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-2702.1
Comment Excerpt Number: 88

Comment: Units Cannot Obtain the Worst Case Fuel During Emissions Testing.
The Proposed Rule requires that units required to demonstrate compliance via stack testing must conduct fuel analysis to establish maximum fuel pollutant input levels. 75 FR 32057. This "worst-case fuel" requirement is unreasonable. EPA's theory apparently is that the owner or operator will be able to procure a worst-case fuel that will maximize the fuel chlorine, mercury and/or total selected metals content without exceeding the Emission Limitation in Table 1. In

fact, EPA suggests in §63.7520 that the owner or operator may have to conduct more than one performance test to accomplish this. The iterative process by which an owner or operator must search for fuels and then conduct performance tests until the worst-case fuel is found will be very time consuming and expensive and is unnecessary.

The same result can be accomplished by requiring the owner or operator to perform the initial performance test using the same fuel that has typically been fired in each boiler. The results of the performance test can then be used to prorate the actual chlorine, mercury and/or total selected metals content of the fuel to the worst-case conditions that would meet the emission limits. The owner or operator would then simply have to maintain the fuel chlorine, mercury and/or total selected metals content below the prorated values established during initial performance test, regardless of the fuel supplier. A new performance test could then be required if the fuel chlorine, mercury, and/or total selected metals content exceeded the prorated values established during the performance test.

Response: See response to comments EPA-HQ-OAR-2002-0058-3213.1, excerpt 126 and EPA-HQ-OAR-2002-0058-2763.1, excerpt 28 for discussion of maximum chlorine and mercury input.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-2702.1
Comment Excerpt Number: 89

Comment: C. Fuel Quality Limits Should Not Be Established Based on Quality During Initial Performance Test.
Under the Proposed Rule, fuel quality limits are established based on quality during the initial performance test. This approach is unreasonable and does not take into account the inherent variability of fuels. EPA should allow units to establish an operating limit based on extrapolation from fuel content correlated with emissions test data up to the emission limit. Further, EPA should allow units that choose to comply with emissions standards by continuous monitoring (e.g. Mercury CEMS) to avoid setting a fuel quality limit for that monitored constituent, given that continuous monitoring would ensure greater confidence that actual stack emissions are within acceptable limits. Additionally, EPA should allow units to conduct fuel supplier sampling and/or analysis and on-site sampling on a monthly composite sample basis. On-site sampling standards could be established similar to those found in the original MACT rule. The standards contained in that rule included processes for collecting samples and statistical analysis of fuel.

While on-site sampling is appropriate for some units, it is not appropriate for others. Specifically, biomass and some coal units often have large numbers of suppliers and sampling could be burdensome if applied to every new supplier. Therefore, EPA should provide that biomass units need only one representative sample from the fuel pile and that coal units obtain one sample per coal type, not per supplier.

Additionally, according to the Proposed Rule, units that burn a Gas 1 gas in combination with other fuel types do not have to conduct monthly sampling/analysis of the Gas 1 gas under any circumstances. However, it appears that units classified in categories other than a Gas 1 unit are required to routinely sample/analyze all fuel types burned in the unit. This would include non-Gas 1 units that burn some amount of natural gas and refinery gas. Such a requirement would be unreasonable. First, natural gas suppliers generally do not perform a broad spectrum of analysis of the gas supplied. Furthermore, there are only a handful of laboratories in the United States that are capable of conducting analysis of pipeline natural gas. Simply put, the routine analysis of pipeline natural gas would be a complicated process and it should be specifically noted to not be required.

Response: If a source opts to use an alternative monitoring technique, they can submit a monitoring alternative for approval with their site-specific monitoring plan which outlines the use of mercury CEMS, and related performance specification and quality assurance mechanisms. Sources can also submit a fuel monitoring alternative for approval in their fuel monitoring plan to establish an operating limit based on extrapolation from the fuel content used during the initial compliance test and the applicable emission limit for that source.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 99

Comment: Table 8 Item 7 specifies that you may “Only [burn] the fuel types and fuel mixtures used to demonstrate compliance with the applicable emission limit according to 63.7530(c) or (d) as applicable.” Requiring sources to burn only the specific fuel or fuel mixture that was used during testing is a practical impossibility and, furthermore, it makes no sense to require sources to generate the maximum possible Hg and Cl- emissions at all times. That is certainly not the intent of this requirement and the massive increase in Hg and Cl- emissions it would engender is certainly not reflected in the record.

Recommendation: To make this requirement workable, this requirement needs to be reworded as follows “Only [burn] fuel types and fuel mixtures containing less Hg and Cl- than the fuel or fuel mixture used to demonstrate compliance with the applicable emission limit according to 63.7530(c) or (d), as applicable.”

Response:EPA appreciates the commentor's careful review of the language in the table. The intent of the provision in Table 8, item 7.a. is to confirm that sources must not burn fuels that were not evaluated consistent with the compliance procedures in 63.7530. Any new fuel or new fuel mixture must be subject to a fuel analysis, and, if compliance with HCl and mercury limits is determined via stack tests, the chlorine and mercury inputs of the new fuel must be compared to the maximum chlorine and mercury input levels of the fuel type that was used in the stack test.

As such, sources must continue to burn the fuel types and fuel mixtures that were the basis of their compliance determination, until such time as they demonstrate that a new fuel will also meet the standards. Therefore we are not revising this portion of the language in Item 7.a. However, we note that the reference to 63.7530(d) is incorrect. The correct citations for the compliance determination procedures are 63.7530(b) or (c).

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-2702.1
Comment Excerpt Number: 154

Comment: Additional Options For Compliance Demonstration.
While this compliance scheme may be appropriate for some sources, especially ones with very stable fuel supply and usage, it may be very cumbersome and burdensome for other sources. It involves a great deal of recordkeeping and potentially subjects the source to frequent testing requirements. As an example of the complexity this proposed compliance plan involves, Section 63.7550 (c)(4) requires that among other things, the semi annual report is to have "the supplier of the fuel and original source of the fuel." To make the proposed compliance plan work (which CIBO does not believe can be done), the Agency would have to be much more explicit for instance in its definition of the original source of the fuel. And that definition would need to consider as many contexts as exist in the market for fuel generation, distribution, and delivery; e.g., if the fuel is a process fuel generated internally, if the fuel is from a distributor or supplier, and if the fuel is pulled from commercial pipelines that may receive input from numerous companies in varying amounts over rime." It appears that the objective for the operating limits that are based on fuel analysis is to insure that the pollutant (chlorine, metals, mercury) input to the source for a given level of operation does not exceed the input level demonstrated during the performance test, where compliance with emissions limitations and work practice standards was demonstrated.

Response: The supplier normally has fuel quality information and can identify the previous link in the chain of supply. The purpose for this requirement is to ensure the Agency has the ability to determine the content of the fuel as delivered, if the facility did not itself test the fuel. The purpose for including the term "origin" is to specify the supply chain terminus so that the Agency can validate fuel content, if necessary for enforcement purposes.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-2702.1
Comment Excerpt Number: 155

Comment: There are several ways in which this objective can be achieved, in addition to the single compliance method proposed. As an example, compliance could be demonstrated through the use of fuel purchase specifications. Sources would determine from the performance test a maximum fuel pollutant concentration at which the emissions limitations and work practice standards are achieved. For instance, the performance test may demonstrate that fuels containing chlorine in concentrations less than x IbCI/MMBTU allow the source to comply with emissions limitations. The source would then set a fuel specification of x IbCI/MMBTU and would be allowed to burn any fuel of the same general type (e.g., solid, liquid or gas) as long as it met this specification. Sources could require that the fuel supplier provide periodic certification that the fuel meets the specification, based on analysis, or could establish an internal sampling and analysis program for that purpose. In any case, where common fuels are utilized in more than one unit, common fuel quality data should be maintained and considered applicable to all such units. Continuous compliance could also be demonstrated through ongoing fuel analysis according to applicable Equations 1, 2 or 3 in § 63.7530.

As an example, sources would (1) establish a fuel input limit (e.g., IbCl/MMBTU) based on the compliance test as described in the proposal (with an allowance for extrapolation as proposed by CIBO elsewhere in these comments); (2) periodically sample and analyze each fuel for constituent concentration and heating value according to a specified sampling and analysis plan; (3) monitor the daily usage of each fuel; (4) calculate the average total daily constituent input (lb/MMBTU) accounting for all wastes fed; and (5) demonstrate that the average daily constituent input rate averaged over each month of operation does not exceed the operating limit. This option would afford the source the opportunity to vary fuel mixes, while still insuring that protective operating limits are met.

Response: See response to comment EPA-HQ-OAR-2002-0058-3213.1, excerpt 126 for flexibility in exceeding the maximum fuel input and the use of fuel purchase specifications.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 169

Comment: Proposed 63.7525(c) also requires that stack tests be performed at maximum normal operating load while burning the type of fuel or mixture of fuels that have the highest content of mercury and chlorine. It is impossible to operate a boiler at precisely the maximum normal operating load or the highest content of chloride and mercury. If these requirements are maintained, both of them should be reworded to require the test be performed at or near the maximum operating load and chloride and mercury level. This would make these requirements feasible and comport with normal stack testing practice, where operation of a combustion source at between 80 and 100% of design capacity is typically considered representative of maximum normal operation for performance test purposes.

Response: The meaning of the term is sufficiently clear. To use more ambiguous language would simply open the door to reduced heat rates and lower than likely emissions during testing. The language as written is sufficient.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 171

Comment: The requirement for doing performance tests at maximum chloride and mercury applies even if testing for chloride and mercury is waived under the provisions of proposed 63.7515(b)-(d) or because fuel testing will be used. There is certainly no purpose in increasing chloride and mercury emissions when not performance testing for these species. Thus, the requirement to performance test at maximum chloride and mercury levels in 63.7515(c) should also be waived if performance tests are not being done for those species.

Recommendation: Revise 63.7515(c) to waive the requirement to test at maximum chloride and mercury levels if these pollutants are not being measured in a particular performance test.

Response: Because we specifically either test of Cl and Hg or specifically waive the duty to do so as a result of good performance, there is not a reason to burden other tests with this particular requirement. We have added a waiver to section 63.7515(c) of the final rule.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 188

Comment: Proposed 63.7515(f) calls for monthly fuel monitoring for Hg and Cl-, if you opt to use fuel analysis to show compliance. It states If you burn a new type of fuel, you must conduct a fuel analysis before burning the new type of fuel in your boiler or process heater. As discussed in our previous comment, testing every stream is not possible for the very common blended fuel gas systems and there certainly is no way to test every startup, shutdown, malfunction or maintenance gas stream prior to mixing it into the blended gas stream.

Recommendation: In 63.7515(f), it should be made clear that requirement does not apply to adding or removing streams from a blended fuel gas system or changing the relative proportions of streams mixed into those fuel gas systems.

Response: The fuel mix should never result in any greater Cl or Hg emissions than as tested. This should be determinable by simple arithmatic associated with the content of the components to the fuels stream. The facility should have sufficient records to document their actual fuels mix would not be expected to emit pollutants at greater than found in the performance test. These calculations should be kept as part of the fuels recordkeeping and would suffice to meet the requirements of the rule. The rule as also added certain provisions to exempt units that serve as control devices for other MACT regulated exhaust streams, and has modified the definitions of gas 1 and gas 2 subcategories which should also reduce the concerns for the commenter.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-2702.1
Comment Excerpt Number: 19

Comment: Having said that, we are very concerned about the particular method of accounting for variability employed by the Agency in the proposal. EPA proposes to account for both "within test" and "between test" variability by calculating the 99% upper prediction level of the available and relevant emissions testing data. See, e.g., id. at 72976-7.

In concept, such an approach makes sense because setting the floor at the 99% upper prediction limit ostensibly would cause the floor to encompass virtually the entire range of emissions reasonably expected by the better performing sources from which the data were derived if the data encompassed all variations that can impact those emissions and the emissions test/fuel quality data were truly random throughout the population. In practice, however, this approach is flawed because the underlying data are not, in fact, representative of the range of expected operations and true variability that reasonably should be expected from the better performers. The reason is that the emissions data relied upon in the proposal were produced during reference method performance testing under very limited operating conditions, and with a very limited variation in potential fuel quality.

Performance testing is required to be conducted under "representative operating conditions." See 40 C.F.R. § 60.55c(b)(1). The rules do not define the term "representative operating conditions." However, EPA’s National Stack Testing Guidance suggests that such conditions: (1) represent the range of conditions under which the facility expects to operate (regardless of the frequency of the conditions); and (2) are likely to most challenge the emissions control measures of the facility (but without creating an unsafe condition). Clean Air Act National Stack Testing Guidance at 14. This guidance further defines "representative" as "normal" as it states that "The MACT program further defines representative performance as normal operating conditions" and again when describing the performances test conditions as described above to be "under. .those representative (normal) conditions. .." Id. Of course, as expressly stated in the document itself, the National Stack Testing Guidance is "intended solely as guidance" and, as such, "is not a regulation." Id. at 2.

Properly conducted, performance tests are, indeed, a reliable measure of compliance at a given point in time with the relevant standard. However, such tests typically should not be expected to reveal the true range of variability in operating conditions because sources strive to maintain rigorous, yet consistent, operating conditions during tests, between testing runs within a given testing session, and between testing sessions. As indicated by the Stack Testing Guidance, the goal of performance testing is to challenge the applicable control device or control measure to assure that compliance will be maintained under rigorous conditions. Variable operations during testing are inconsistent with the purpose and intent of such testing. In addition, some reference method tests are most applicable for use under steady state conditions.

Moreover, while owners and operators may seek to conduct testing at reasonable worst case conditions to assure compliance during less rigorous conditions, it is entirely possible that operations during less rigorous conditions could nevertheless accommodate operational variation that would not threaten compliance with the standard, but could be relevant when the data are used to set standards on a pollutant-specific basis rather than a unit-specific basis. As a hypothetical example, the most rigorous testing condition for HCl emissions from a given boiler might be a fuel with high halide content. Thus, it would be logical for testing to be performed under these conditions. However, other HAP constituents in the fuel – such as metals – would not necessarily be at "worst case" levels during testing focused on halides. In this scenario, the testing might show extremely low levels of metals emissions, which would not necessarily reflect higher levels of such emissions that might occur during normal operations. It is also typically not feasible to actually obtain "worst case" fuel quality for emissions testing purposes simply due to natural variability in fuel quality, especially coal.

In order to address these limitations, CIBO recommends that EPA utilize a site specific fuel analysis plan approach and correlate fuel quality during emissions testing to emissions measured, and then use ongoing fuel analysis on an appropriate time basis to determine ongoing compliance based on emissions control performance achieved during the emission test. For example, some existing coal fired units might be conducting daily coal sampling and analysis for sulfur and HHV, so accumulating the individual coal samples for a month and preparing a monthly composite for HHV, S, Cl, and Hg analysis would allow determination of projected emissions over that month for the operational boilers. In that way, a 12 month rolling average emission rate could be determined relative to the emission limit. This approach would then allow use of actual fuel quality during the emissions test to not become an artificial limit to operation of the units, while still assuring emissions comply with the limits.

Response: The rule does not define representative operating load conditions but the final rule has modified the requirements in Table 8 to ensure that the boiler load does not exceed 12-hour block average load does not exceed the load of the performance test. It is expected that sources will test at conditions that will not affect their ability to operate at the loads necessary to sustain their processes. See response to EPA-HQ-OAR-2002-0058-2845.1, excerpt 34 for recognition that worst-case for one parameter may not be worst-case for another parameter. See response to comment excerpt EPA-HQ-OAR-2002-0058-3213.1, excerpt 126 for discussion of a plan to incorporate a site-specific fuel analysis monitoring plan.

Commenter Name: John Hopewell

Commenter Affiliation: American Coatings Association
Document Control Number: EPA-HQ-OAR-2002-0058-2886.1
Comment Excerpt Number: 14

Comment: Facilities should not be required to do fuel analysis for each fuel supplier

Response: According to the definition of fuel type, a change in fuel supplier in and of itself does not necessitate retesting. See response to comment EPA-HQ-OAR-2002-0058-3213.1, excerpt 126 for flexibility in exceeding the maximum fuel input.

Commenter Name: G. Vinson Hellwig
Commenter Affiliation: Michigan Department of Natural Resources and Environment
Document Control Number: EPA-HQ-OAR-2002-0058-2837.1
Comment Excerpt Number: 4

Comment: It appears that in an effort to provide boiler and process heater operators with the flexibility to select from a menu of available fuels, EPA has fashioned a system where the emission limit for a boiler burning multiple fuels will be determined after the fuel is combusted, by looking back to calculate whether the boiler exceeded the "designed to combust" threshold for coal or biomass or liquid fuel. The proportions or types of fuels combusted during a 12-month operating period may or may not align with those combusted during the performance test.

In the current proposed subject rule, EPA has made an effort to define reasonable subcategories based on the fuel burned, resulting in four primary groups, coal-fired, biomass-fired, liquid-fired, and gas-fired units. Within these groups are the boiler subcategories, based on equipment design. To define the MACT floor, the best approach is to review the results of performance tests conducted during actual operation of a specific type of boiler burning a specific type of fuel. EPA has taken this approach to define the MACT floors. However, to determine which limit is applicable to a specific boiler, EPA appears to have defined the subcategories based on what fuel a boiler is "designed to combust" rather than actual operation. This change from the approach proposed in the 2004 MACT rule (40 CFR 63.7530) to address fuel mixtures used in boilers and process heaters is not necessary. We recommend that EPA should establish MACT limits for each major category of fuels and require compliance verification for use of multiple fuels using the methods found at 40 CFR 63.7530.

Response: Please see the preamble for discussion of combination fuel units which will help mitigate the concerns of the commenter since most multifuel boilers combust combinations of biomass and coal. Further, in the final rule EPA has defined the subcategories based on the annual heat input contribution from each fuel type.

Commenter Name: Nilaksh Kothari
Commenter Affiliation: Manitowoc Public Utilities

Document Control Number: EPA-HQ-OAR-2002-0058-2810.1
Comment Excerpt Number: 6

Comment: MPU recommends that EPA modify the process for establishing maximum input limits during performance testing. For example, the proposed rule would require the measurement of the chlorine content in the input fuel and use that value to establish a maximum chlorine input limit. The proposed rule does not consider the ability a process may have to inherently control emissions. It would certainly be possible to calculate a removal efficiency that could be used to calculate how high the chlorine content of the input fuel could be before an exceedance of an emission limit would occur.

The rule also proposes to establish site specific minimum sorbent injection rates based on pollutant performance tests. This requirement ignores the fact that sorbent injection rates are affected and controlled by other pollutants and boiler operating conditions. For example, in a CFB boiler the fuel sulfur content, bed temperature, and bed depth will have a major impact on the required sorbent injection rate.

Response: EPA has retained the fuel measurement provisions in the final rule. In many instances EPA expects the control device to be operating at its maximum efficiency during the inital performance test in order to achieve the emission limits under the worst case fuel and load conditions. We recognize that some units and fuel type combination may be able to install controls that operate at a fraction of their maximum removal efficiencies in order to meet the limit. See response to comment excerpt EPA-HQ-OAR-2002-0058-3213.1, excerpt 126 for response to cases where inherently low chlorine or mercury fuel inputs may have exceptions to the fuel testing requirements.

Commenter Name: Rachel Smolker
Commenter Affiliation: Biofuelwatch
Document Control Number: EPA-HQ-OAR-2002-0058-2805.1
Comment Excerpt Number: 8

Comment: Secondary Materials as Fuel Sources.
The existing biomass power industry consists of industrial boilers that fire from wood waste or wood liquors. According to the USFS about 1 -2% of mill wood waste goes unused. [Smith, W.B., et al. 2007. Forest Resources of the United States, 2007. United States Forest Service, Gen.Tech Report WO-78. December, 2008] Therefore, the biomass power industry is looking to new materials to provide fuel. According to various projections of biomass supply, construction and demolition debris (C&D) is likely to play a major role in meeting this need. Some federal and state legislation already permit the use of C&D as a renewable fuel. Even after sorting, this fuel stream inevitably contains wood treated with copper-chromium-arsenate (CCA), and can contain other wood preservatives, including PCB's. Unfortunately, it appears from EPA's recent draft waste rule that the agency does not appreciate the potential for contamination of these secondary materials. Visual sorting of secondary fuel materials in C&D waste and disaster debris is expensive and time-consuming. Wood treated with CCA can sometimes be identified by its

green tint, however after a number of years this green stain fades. Identifying C&D that is painted with lead paint is also difficult unless a restrictions is set restricting all painted wood, but the industry has consistently resisted such restrictions. EPA appears to not appreciate how difficult it is to control the contamination levels in such fuel streams. The Agency states,

For units that choose to comply with either the mercury emission limit or the HCl emission limit based on fuel analysis rather than on performance stack testing, we are proposing that you maintain daily fuel records that demonstrate that you

burned no new fuels or fuels from a new supplier such that the mercury content or the chlorine content of the inlet fuel was maintained at or below your maximum fuel mercury content operating limit or your chlorine content operating limit set during the performance stack tests.

However, C&D materials and disaster debris by their definition are materials whose characteristics are determined by the demolition of structures with varying age and compositions and thus are constantly changing. How does the EPA propose to define whether the fuel type constitutes a change or mixture that would require recalculations and perhaps new performance tests? Monitoring emissions based on daily record as an alternative to stack emissions is unrealistic at best.

Response: Unless C&D materials have received a non-waste determination, and therefore do not contain any significant level of contaminants, these materials are not considered fuels and are not expected to be combusted in affected sources under this rulemaking. EPA has retained its definition of fuel type in the final rule. Biomass encompass a broad range of materials which as the commenter points out are not all homogeneous. The term biomass encompasses cellulosic biomass such as forest-derived biomass, sawdust, wood chips, bark, bagasse, biomass crops used specifically for energy production, clean wood found in disaster debris, and resinated wood products. Whereas a switch in the source of wood chips would not constitute a new fuel, a switch from wood chips to a nonwood biomass, such as bagasse should be considered a switch in fuel given the differing physical and chemical characteristics of wood as compared to the nonwood biomasses. Note that the definition of fuel type does not classify individual fuel types received from different suppliers as new fuels.

Commenter Name: Gary Melow
Commenter Affiliation: Michigan Biomass
Document Control Number: EPA-HQ-OAR-2002-0058-2776.1
Comment Excerpt Number: 17

Comment: We understand from the proposed rule that we must establish a maximum mercury and chlorine content of the fuel during the performance stack test, and maintain levels of chlorine and mercury at or below those levels to assure continuous compliance. If a fuel with a higher mercury or chlorine content were to be considered we assume there is a provision for running this fuel and conducting stack testing to confirm continued compliance. If such a stack test indicates emissions in excess of the emission limit, then the previous mercury or chlorine content that demonstrated compliance with the emission limit applies. EPA must appreciate that there may be several “trial and error” type runs with emission testing to establish the maximum acceptable chlorine and mercury content, and some of this testing may need to take place after the compliance deadline if other fuel types were to become available in the future.

Response: The general Part 60 rules provide flexibility for testing new fuels (60.8). The facility would need to seek approval for these tests after initial performance testing. Use of fuel content data and heat and associated emissions factors should be sufficient to inform the facility as to whether it needs to seek EPA approval for such tests.

Commenter Name: Edward E. Quick
Commenter Affiliation: Celanese International Corp
Document Control Number: EPA-HQ-OAR-2002-0058-2840.1
Comment Excerpt Number: 17

Comment: Affected sources using fuel specifications to comply with Hg and chlorine HCl emission limits must be allowed to establish fuel quality limits based on extrapolated test results. Conditions achieved during a one-time emissions test are not representative of conditions that occur over an extended period of time. The available compliance methods in the proposed regulation do not enable the affected source to accurately identify the range of representative operating conditions that will meet the Hg and HCl emission limits.

Options that have typically been used by other source categories to simulate worst-case operating conditions (such as spiking of fuels and on-site sample analysis) are not feasible and are economically burdensome for coal fired boilers. Analytical methods for stack emissions (Hg and HCl) and fuel composition (Hg and Cl) that produce real time results are costly and not common practice based on available analytical test programs. Other source categories simulate worst case conditions for multiple pollutants by spiking process streams. Spiking coal with Hg and Cl to simulate worst-case conditions is impractical. One reason is that spiking a solid fuel does not ensure a homogenous fuel source. Secondly, Hg emissions depend on the type and composition of coal, not solely on the amount of Hg within coal. Spiked mercury would upset the balance and composition of coal being burned. This significantly altered composition would not represent actual operating conditions. For these reasons, the current compliance provisions do not allow operators of coal boilers to simulate worst case conditions during the compliance demonstration.

Typical performance tests involve off-site analysis of samples collected during stack testing. Thus, the compliance determination is made days after the performance test when analytical results are made available. Operators therefore conduct these “blind” tests under best-case conditions to ensure that the standards are met. These best-case conditions are likely to produce test results that are a fraction of the emissions standards. It is impracticable for operators of these sources to operate continuously within the Hg and Cl composition parameters established during these onetime performance tests due to fuel availability and composition variability as described in Celanese Comment 3.

For these reasons, the proposed rule must allow affected sources to extrapolate operating parameters from the test results to demonstrate compliance with emission limits. Parametric limits established by extrapolation better represent the range of conditions under which the source would operate. For example, consider an affected source that controls HCl and Hg emissions by limiting the Cl and Hg content of coal. While demonstrating compliance with the Hg emissions standard, the source also demonstrates an HCl emission rate that is a fraction of the emission standard. The source determines that HCl and Hg emissions are linearly related to Cl and Hg content of coal. Based on this analysis, the operator of the source must be able to extrapolate fuel content of Cl and Hg to demonstrate compliance with established emission limits for HCl and Hg. If this extrapolation process is prohibited, operators of these sources would be required to perform multiple stack tests that are unnecessary. In addition, establishment of parametric limitations based solely on fuel composition achieved during the performance test is unduly burdensome and in some cases will prohibit sources from operating when fuel variability limits operation. Therefore, to prevent this certain occurrence, EPA must allow the affected source to extrapolate the fuel composition parametric limit based on test conditions.

Response: The maximum input levels for chlorine and mercury determined from equations 7 & 8, respectively, are not operating limits but are rather levels which can be used to provide an indication of whether a fuel switch may affect the source's compliance status.

Commenter Name: Gary W. Kruger
Commenter Affiliation: Morton Salt
Document Control Number: EPA-HQ-OAR-2002-0058-2883.1
Comment Excerpt Number: 19

Comment: While this compliance scheme may be appropriate for some sources with very stable fuel supply and usage, it may be very cumbersome and burdensome for other sources. It involves a great deal of recordkeeping and potentially subjects the source to frequent testing requirements. As an example of the complexity this proposed compliance plan involves, Section 63.7550 (c)(4) requires that among other things, the semi annual report is to have the supplier of the fuel and original source of the fuel. To make the proposed compliance plan work (which we do not believe can be done), the Agency would have to be much more explicit for instance in its definition of the original source of the fuel. Furthermore, that definition would need to consider as many contexts as exist in the market for fuel generation, distribution, and delivery; e.g., if the fuel is from a distributor or supplier or if the fuel is from a specific mine/property or wash plant. It appears that the objective for the operating limits that are based on fuel analysis is to ensure that the pollutant (chlorine, metals, mercury) input to the source for a given level of operation does not exceed the input level demonstrated during the performance test, where compliance with emissions limitations and work practice standards was demonstrated.

Response: The amount of detail that is necessary in documenting the original source of the fuel is necessarily a case-specific decision, related to how much information is necessary to determine if the fuel constitutes a new fuel, consistent with the definition for "fuel type." Note that the rule does not specifically require documentation of the original source of the fuel in all instances, but rather requires a description of the fuel in 63.7550(c)(4), and the type(s) of fuel used in 63.7555(d)(1).

Commenter Name: Steven G. Hanson
Commenter Affiliation: Graphic Packaging International
Document Control Number: EPA-HQ-OAR-2002-0058-2723.1
Comment Excerpt Number: 26

Comment: The performance testing requirements for a multi-fuel boiler are unclear. For example, GPI — Macon Mill operates an existing unit that would be classified as a "designed to burn biomass" unit because on an annual basis, the heat input capacity of coal is less than 10%. However, on a short-term basis, the unit is capable of combusting 100% coal.[8 In reviewing hourly fuel usage data on this unit, in the past two years, GPI has operated the unit at greater than 10% coal (heat input basis) for approximately 8% of the total hours of operation, with isolated hourly spikes around 90% of the heat input at that time.] As the coal potentially has the highest levels of HC1 and Hg, would GPI — Macon Mill be required to test this unit at 100% coal and compare those emissions to the limitations for boilers designed to burn biomass as that would be the classification? Or is the intent for such units to test using a fuel mix that is representative of typical operations? GPI — Macon Mill is also concerned about the possibility of establishing different operating limits for different fuel scenarios as the practical implementation could be challenging. GPI — Macon Mill requests that EPA give more consideration to the challenges of conducting performance tests on multi-fuel boilers and provide more specific input as to the expectations for such performance testing.

Response: The Agency practice has been to burn the worst mix of fuel expected to be used, based on past performance. If there is no reasonable expectation that the facility would use more than 10% coal, and never has, then that level of coal would be appropriate.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 181

Comment: EPA Should Provide Flexibility In Determining Appropriate Fuel Input Operating Limits. The general compliance plan outlined in the proposed rule is that sources; demonstrate compliance with applicable emissions limitations and work practice standards through the conduct of an initial performance test; establish operating limits based upon results of the performance test; conduct monitoring and maintain records demonstrating that the source is operated on a continuous basis consistent with the operating limits established during the performance test; and periodically repeat the performance testing.

Operating parameter limits based on fuel input analysis (e.g., HCI and Hg), are established using Equations 7 and 8 in section 63.7530. Then, on a continuing basis, facilities are required to keep extensive records of all fuels burned (i.e., fuel type, fuel supplier, fuel mixture, and fuel usage amount) in each boiler or process heater during each compliance reporting period. If a source changes fuels (type, supplier, etc.), it must re-calculate its fuel input values using applicable Equation 7 or 8. If the re-calculated value exceeds the existing limit, the source is required to conduct a new performance test and establish new operating limits.

While this compliance scheme may be easy to manage for some sources, especially ones with very stable fuel supply and usage, it may be very cumbersome and burdensome for other sources with variable fuel suppliers and fuel mixes. This approach involves a great deal of recordkeeping and potentially subjects the source to frequent testing requirements if fuel content varies, regardless of the margin of compliance shown during the initial performance test. Under the proposed rule, even if a unit is operating at 50% of the applicable emission limit, the facility would be required to re-test if the fuel chloride input increases 1% over the level achieved during the initial performance test.

A more appropriate approach is to allow the source to set operating parameters at levels that generate emissions at the emission limits established in the rule. This is the only approach which meets the requirements of the CAA, since it is the only approach that does not impose a beyond the floor limit which has not been justified per the requirements of section 112(d). Under this approach, the source would simply do the performance test using its normal fuel mix, determine operating conditions that show compliance and then adjust those conditions, using engineering calculations to assure it would meet the emissions standards established in Table 1 or 2. If the initial performance test shows emissions at 50% of the standard at a particular mercury or chloride fuel input, the fuel input limits should be set at a level higher than the performance test values, taking into account control device operating parameters as appropriate. This approach would be environmentally beneficial and would greatly reduce burdens.

Response: See response to comment EPA-HQ-OAR-2002-0058-3213.1, excerpt 126 for flexibility in exceeding the maximum fuel input.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 182

Comment: Compliance could also be demonstrated through the use of fuel purchase specifications. Sources would determine from the performance test a maximum fuel pollutant concentration at which the emissions limitations are achieved. For instance, the performance test may demonstrate that fuels containing chlorine in concentrations less than x lb Cl /MMBtu allow the source to comply with emissions limitations. A facility should be allowed to extrapolate an allowable fuel input based on a comparison of performance test conditions to the applicable emission limit. The source would then set a fuel specification of x lb Cl/MMBtu and would be allowed to burn any fuel of the same general type (e.g., solid, liquid, or gas) as long as it met this specification. Sources could require that the fuel supplier provide periodic certification that the fuel meets the specification, based on analysis, or could establish an internal sampling and analysis program for that purpose. In any case, where common fuels are utilized in more than one unit, common fuel quality data would be maintained and considered applicable to all such units. Continuous compliance could also be demonstrated through ongoing fuel analysis.

As an example, sources would (1) establish a fuel input limit (e.g., lb Cl/MMBtu) based on the compliance test as described in the proposal (with an allowance for extrapolation); (2) periodically sample and analyze each fuel for constituent concentration and heating value according to a specified sampling and analysis plan; (3) monitor the daily usage of each fuel; (4) calculate the average total daily constituent input (lb/MMBTU) accounting for all fuels fed; and (5) demonstrate that the average daily constituent input rate averaged over each month of operation does not exceed the operating limit. This option would afford the source the opportunity to vary fuel mixes, while still insuring that protective operating limits are met.

Given the wide variety of sources impacted by this proposal, it is reasonable to provide flexibility in how sources demonstrate compliance, as long as clearly-defined compliance objectives are met. ACC requests that EPA include the compliance schemes discussed above in the final rule as allowable optional compliance strategies. We are willing to work with the agency to further refine these strategies. Additionally, ACC requests that the final rule include an allowance for a source to use, with prior Agency approval, other compliance strategies that may be more appropriate on a site-specific basis.

Response: See response to comment EPA-HQ-OAR-2002-0058-3213.1, excerpt 126 for flexibility in exceeding the maximum fuel input and the use of fuel purchase specifications.

Commenter Name: Gary W. Kruger
Commenter Affiliation: Morton Salt
Document Control Number: EPA-HQ-OAR-2002-0058-2883.1
Comment Excerpt Number: 9

Comment: There exists an inherent variability in coal quality of the nation's coal supply. The proposed rule requires performance testing and fuel analysis for the worst case fuels with the highest chlorine, mercury, and/or total selected metals content in order to establish operating parameter limits. Due to the fuel variability, it is impossible to identify a worst case fuel, and would require a great deal of recordkeeping and additional performance testing. In addition, the truck and belt fuel sampling and daily fuel usage records as outlined in the proposed rule are not workable to some units as the coal bins are connected directly to the boilers. This approach also results in a fuel sample which is not representative of the fuel that is actually being combusted in the boiler during the performance testing due to the storage capacity between the truck and the boiler.

Response: See response to EPA-HQ-OAR-2002-0058-2845.1, excerpt 34 for recognition that worst-case for one parameter may not be worst-case for another parameter. EPA-HQ-OAR-2002-0058-2763.1 excerpt 28 for response to maximum mercury and chlorine inputs.

Commenter Name: Douglas J. Van Pelt
Commenter Affiliation: ExxonMobil
Document Control Number: EPA-HQ-OAR-2002-0058-2968.1
Comment Excerpt Number: 28

Comment: Performance testing is required to be conducted under "representative operating conditions." See 40 C.F.R. section 60.55c(b)(1). The rules do not define the term "representative operating conditions." However, EPA's National Stack Testing Guidance suggests that such conditions: (1) represent the range of conditions under which the facility expects to operate (regardless of the frequency of the conditions); and (2) are likely to most challenge the emissions control measures of the facility (but without creating an unsafe condition). Clean Air Act National Stack Testing Guidance at 14. This guidance further defines "representative" as "normal" as it states that "The MACT program further defines representative performance as normal operating conditions" and again when describing the performances test conditions as described above to be "under...those representative (normal) conditions...." Id. Of course, as expressly stated in the document itself, the National Stack Testing Guidance is "intended solely as guidance" and, as such, "is not a regulation." Id. at 2.

Properly conducted, performance tests are, indeed, a reliable measure of compliance at a given point in time with the relevant standard. However, such tests typically should not be expected to reveal the true range of variability in operating conditions because sources strive to maintain rigorous, yet consistent, operating conditions during tests, between testing runs within a given testing session, and between testing sessions. As indicated by the Stack Testing Guidance, the goal of performance testing is to challenge the applicable control device or control measure to assure that compliance will be maintained under rigorous conditions. Variable operations during testing are inconsistent with the purpose and intent of such testing.

Moreover, while owners and operators may seek to conduct testing at reasonable worst case conditions to assure compliance during less rigorous conditions, it is entirely possible that operations during less rigorous conditions could nevertheless accommodate variation that would not threaten compliance with the standard, but nevertheless could be relevant when the data are used to set standards on a pollutant-specific basis rather than a unit-specific basis. As a hypothetical example, the most rigorous testing condition for HCl emissions from a given boiler might be a feed with high halide content. Thus, it would be logical for testing to be performed under these conditions. However, other HAP constituents in the feed – such as metals – would not necessarily be at "worst case" levels during testing focused on halides. In this scenario, the testing might show extremely low levels of metals emissions, which would not necessarily reflect higher levels of such emissions that might occur during normal operations.

Response: See response to EPA-HQ-OAR-2002-0058-2702.1, excerpt 19 for explanation of representative operating conditions. See response to EPA-HQ-OAR-2002-0058-2845.1, excerpt 34 for recognition that worst-case for one parameter may not be worst-case for another parameter. See response to comment excerpt EPA-HQ-OAR-2002-0058-3213.1, excerpt 126 for discussion of a plan to incorporate a site-specific fuel analysis monitoring plan.

Commenter Name: Alicia Oman
Commenter Affiliation: National Association of Manufacturers
Document Control Number: EPA-HQ-OAR-2002-0058-2845.1
Comment Excerpt Number: 34

Comment: While owners and operators may seek to conduct testing at reasonable worst case conditions to assure compliance during less rigorous conditions, it is entirely possible that operations during less rigorous conditions could nevertheless accommodate variation that would not threaten compliance with the standard, but nevertheless could be relevant when the data are used to set standards on a pollutant-specific basis rather than a unit-specific basis. As a hypothetical example, the most rigorous testing condition for HCl emissions from a given boiler might be a feed with high halide content. Thus, it would be logical for testing to be performed under these conditions. However, other HAP constituents in the feed – such as metals – would not necessarily be at “worst case” levels during testing focused on halides. In this scenario, the testing might show extremely low levels of metals emissions, which would not necessarily reflect the higher levels of such emissions that might occur during normal operations.

Response: Sources must test under conditions that are representative of the source’s ability to comply continuously with the emission standards. If the source believes that conditions at maximum normal operating load are not reflective of conditions that most challenge the source's ability to comply, they may specify what other conditions are more reflective of continuous compliance in their test plan, required under the General Provisions at 63.7(c). Further, the regulations have been amended to clarify that you must conduct performance stack tests at the maximum normal operating load while burning the type of fuel or mixture of fuels that has the highest content of particulate matter, as well as of mercury and chlorine. EPA recognizes that this may result in the need to conduct more than one performance test, as reflected in the language at § 63.7520(c) which states, "These requirements could result in the need to conduct more than one performance test."

Emissions Averaging

Commenter Name: Norbord Industries
Commenter Affiliation: Norbord Industries
Document Control Number: EPA-HQ-OAR-2002-0058-0854.1

Comment Excerpt Number: 10

Comment: EPA should establish an emission average alternative for PM. Many boilers will not be able to meet the proposed PM standard but could potentially reduce PM emissions from other site sources.

Response: The emissions averaging provision in the final rule is applicable to PM emissions.

Commenter Name: Randolph Price
Commenter Affiliation: Consolidated Edison Company of New York
Document Control Number: EPA-HQ-OAR-2002-0058-1869.1
Comment Excerpt Number: 5

Comment: EPA's proposed restrictions on emissions averaging are not consistent with the scale of industrial, commercial and institutional boilers.

EPA appears to have relied heavily on the rationale for emissions averaging as part of a MACT standard presented in its 1994 Hazardous Organics NESHAPS ("HON") found at 59 Fed. Register I 9425 (April 22, 1994).[Paragraph 5 of Sectioj V.D, "Emissions Averaging," of that 1994 FR notice includes a sentence that states, "However, the HON emissions averaging system…should not be viewed as setting a precedent for future MACT standards."] One of the provisions that EPA included in the current proposal is that there would be "no averaging between individual sources that are not part of the same affected source." Such a restriction may be reasonable when the "affected source" is a large refinery or electric generating power plant with a number of individual sources on one distinct and expansive parcel. However, industrial boilers, particularly those associated with district steam systems, are often smaller sources that are spread throughout a distinct system or process, but located on separate property parcels. In actuality, the emission sources in such a system could be in closer proximity to each other than sources within the geographic boundary of a large refinery operation.

A particular example would be a college campus that includes several boilers, but whose buildings are spread over a number of property parcels within a small geographic area, such as a small city. Typically, all of the boilers provide steam to the same underground system and are under common control and management. In such an instance, a significant investment in fuel-switching or control equipment in one boiler could be used to offset the emissions from the remaining boilers on the system, resulting in an overall reduction that, averaged, allows all of the boilers to meet the MACT standard. Allowing these interconnected boilers to employ emissions averaging would maximize the incentive for one or more of the boilers to switch to the lowest-possible emitting fuel or to install the most effective control technology. Accordingly, to promote this efficiency without sacrificing the desired air quality management objectives, the Company suggests the following additional text (shown in ALL CAPS) to proposed § 63.7522(a), found in the Federal Register notice at page 32053:

"(a) As an alternative to meeting the requirements of § 63.7500 for particulate matter, HCI, or mercury on a boiler or process heater-specific basis, if you have more than one existing boiler or process heater in any subcategory located at your facility OR IF NOT ALL ARE LOCATED ON A COMMON PARCEL, BUT ARE CONNECTED TO A COMMON PIPING OR PROCESS SYSTEM AND ARE UNDER COMMON OWNERSHIP AND CONTROL you may demonstrate compliance by emission averaging, if your averaged emissions are within 90 percent of the applicable emission limit,. according to the procedures in this section."

To make the provisions consistent, the text of § 63. 7522(g)(4)(i) (Federal Register notice page 32054) should be modified as follows:

"(4) The applicable regulatory authority shall not approve an emission averaging implementation plan
containing any of the following provisions:

(i) Any averaging between emissions of differing pollutants or between differing sources (EXCEPT AS PROVIDED FOR IN § 63.7522(a));"

Response: EPA thanks the commenter for their input but notes that 'facility' is the preferred term in this instance. EPA must ensure that compliance provisions such as emissions averaging have appropriate limitations to ensure equal protection of human health and the environment. Further, 'facility' was the term used in the emissions averaging provisions of the vacated rule.

Commenter Name: Arlington Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1779
Comment Excerpt Number: 79

Comment: Thirty percent of these costs, however, will be related to non environmental improvements such as redesigning stacks to account for the provisions of emissions averaging which do not allow us to average over subcategories when –- for boilers that burn similar fuels .

An example of this is one of our facilities burns -– has three boilers connected to a common stack. Two of them burn coal with tangentially fired units; the other one is stoker fired. They had different limits. Under the current rule we would not be able to emissions average these boilers; therefore, a significant amount of investment required to just separate the stacks in order to meet the rule. Again, these investments under the current rule would not benefit the environment at all.

Response: See response to comment EPA-HQ-OAR-2002-0058-3213.1, excerpt 175 for emission averaging between subcategories.

Commenter Name: Stephen R. Gossett
Commenter Affiliation: Eastman Chemical Company
Document Control Number: EPA-HQ-OAR-2002-0058-3137.1
Comment Excerpt Number: 1

Comment: Dioxins/furans should be included.

A source should be allowed to comply with the dioxin/furan (D/F) standard via emission averaging. While Eastman does not believe it is appropriate to set numerical emission standards for D/F (see comments elsewhere), if the final rule does include such numerical standards, a source with multiple units could choose to comply by installing a post-combustion control (such as powder activated carbon injection) to reduce D/Fs (note, this example does not imply Eastman believes such technology has been demonstrated on industrial boilers) on some units at a facility. By the same rationale that would justify allowing use of emission averaging for other HAPs, sources should be allowed the flexibility to over-control at some units at a facility and under-control at others in order to reduce the overall compliance costs for the facility.

Response: See response to comment EPA-HQ-OAR-2002-0058-2801.1, excerpt 36 for discussion of pollutants eligible for emissions averaging.

Commenter Name: Stephen R. Gossett
Commenter Affiliation: Eastman Chemical Company
Document Control Number: EPA-HQ-OAR-2002-0058-3137.1
Comment Excerpt Number: 2

Comment: Carbon monoxide should be included.

Some units may be able to easily meet the proposed CO limits, while, for others, it may impossible. Therefore, CO should be included in the emissions averaging provisions. To facilitate its inclusion, the emission limitation for CO should be expressed in an alternative form – lb/mmBtu. For the case of units using CEMS to measure CO, we reference an existing emission averaging provision for NOx found at 40 CFR 76.11. Heat input should be allowed to be determined using either flow monitors (some units subject to the NOx budget trading program have these already) or using fuel factors and diluent monitors per 40 CFR 60 Method 19.

Response: See response to comment EPA-HQ-OAR-2002-0058-2801.1, excerpt 36 for discussion of pollutants eligible for emissions averaging and response to EPA-HQ-OAR-2002-0058-2702.1, excerpt 206 for alternative units of measure for CO.

Commenter Name: Stephen R. Gossett
Commenter Affiliation: Eastman Chemical Company
Document Control Number: EPA-HQ-OAR-2002-0058-3137.1

Comment Excerpt Number: 3

Comment: Averaging across subcategories should be allowed. The proposed emission averaging provision appears to only allow averaging within a subcategory (see §63.7522(a).

On page 32034 of the preamble, EPA states one of its limits on the scope of emissions averaging is to not allow averaging between sources that are not part of the same affected source. In this case, EPA has elected to define the affected source in §63.7490(a)(1) as all units within a subcategory. We see no reason for EPA to use this definition. Rather all units at a given facility subject to the subpart should be collectively considered the “affected source”. This is how EPA has defined the term in other rules with which we are familiar (e.g. the HON in Subpart F, Polymer and Resins 4 in Subpart JJJ, the MON in Subpart FFFF). The HON in particular we understand is the model EPA is using to guide its policy. By defining the term affected source as all chemical manufacturing process units (CMPUs) at a facility, the HON allows emissions averaging across CMPUs and across emission unit types (vents, storage vessels, transfer racks, wastewater stream). There is no reason in the boiler and process heater MACT for EPA to restrict the emissions averaging alternative as it has proposed. To do so, will prevent some facilities from taking advantage of the opportunity to avoid otherwise cost-prohibitive compliance options by over-controlling some other emission unit in a more cost-effective combination.

Also, by not allowing averaging across the different fuel categories, EPA removes an incentive to burn more natural gas or renewable fuels such as biomass as a strategy to average out emissions from a coal-fired unit.

It is not clear from the proposed rule language if EPA intended to restrict averaging across subcategories. While the wording under the separate stack requirements does seem to have this restriction, the wording under the common stack requirements does not (see Equation 6). In any event, as stated above, there should be no such restriction.

As in the HON, the compliance methodology can easily accommodate subcategories with different emission limits for a given pollutant. This is done basically by calculating a weighted average allowable mass emission and a weighted average actual mass emission each month using heat inputs or steam production for each unit.

At one of its facilities, Eastman operates boilers in two subcategories (stokers and pulverized coal) for which we are likely to take advantage of the emission averaging provision. These boilers are in separate powerhouses. We urge EPA to remove the restriction (or clarify its intent) that such averaging is allowed, regardless of whether the boilers emit through separate or common stacks.

Response: See response to comment EPA-HQ-OAR-2002-0058-3213.1, excerpt 175 for emission averaging between subcatgories.

Commenter Name: Trina L. Vielhauer
Commenter Affiliation: Florida Department of Environmental Protection, Division of Air Resource Management
Document Control Number: EPA-HQ-OAR-2002-0058-2527.1
Comment Excerpt Number: 4

Comment: The Division does not support the emissions averaging concept outlined in the proposal. While such an approach may work satisfactorily for similar emissions units with similar and contemporaneous control equipment, it would not necessarily be appropriate in all cases. In addition, the Division does not believe that emissions averaging among similar units at a facility is within the spirit and intent of the MACT program.

Response: EPA acknowledges the concerns of the commenter. However, it has retained the emission averaging provision in the final rule. The emission averaging concept was also an element of the vacated 2004 rule, and although the format in this final rule is slightly modified from the vacated rule, the same spirit is retained. Further, this revised emission averaging provision includes additional mechanisms that are protective of the public health, such as incorporating a discount factor to determine eligibility for emissions averaging. Further, the final rule includes a provision to have the emissions averaging implementation plans reviewed an approved, upon request in order to allow regulatory authorities to provide input on specific plans.

The final rule is not the first NESHAP to include provisions permitting emission averaging. The legal basis and rationale for emissions averaging were provided in the preamble to the final Hazardous Organic NESHAP (59 FR 19425, April 22, 1994). In general, EPA has concluded that it is permissible to establish within a NESHAP a unified compliance regimen that permits averaging across affected units subject to the standard under certain conditions. Averaging across affected units in the same subcategory is permitted only if it can be demonstrated that the total quantity of any particular HAP that may be emitted by that portion of a contiguous major source that is subject to the NESHAP will not be greater under the averaging mechanism than it would be if each individual affected unit complied separately with the applicable standard. Under this rigorous test, the practical outcome of averaging is equivalent in every respect to compliance by the discrete units, and the statutory policy embodied in the MACT floor provisions is, therefore, fully effectuated.

Commenter Name: John M. Cullen
Commenter Affiliation: Masco Corp.
Document Control Number: EPA-HQ-OAR-2002-0058-2417.1
Comment Excerpt Number: 4

Comment: Emission averaging is an important compliance tool and EPA should continue to include this opportunity in the rule. It should not, however, contain a 10% discount factor, which causes it to lose its intended flexibility.

Response: See response to EPA-HQ-OAR-2002-0058-2808.1, excerpt 30 for the discount factor.

Commenter Name: Stephen R. Gossett
Commenter Affiliation: Eastman Chemical Company
Document Control Number: EPA-HQ-OAR-2002-0058-3137.1
Comment Excerpt Number: 5

Comment: Compliance should be based solely on actual emissions.

The proposed provisions require (1) a demonstration that the average weighted emissions is less than 90 percent of the applicable emissions limit assuming each unit is operating at its maximum rated heat input capacity (see Equation 1) and (2) a demonstration each calendar month that the average weighted emissions is less than the applicable emissions limit using the actual heat inputs for that month.

There is no rationale for the first test and it should be eliminated. Other rules that allow emission averaging (again, see the HON), include no such requirement. Such a requirement could be unduly restrictive. For example, a facility may have one older unit and a newer unit which they would like to average. The older unit may have a much lower capacity factor (ratio of actual usage divided by rated capacity) than the newer one. Older units typically have much more space constraints and a facility may be facing steep compliance costs to bring the older unit into compliance and may have an opportunity to over-control the newer unit. Given that the newer unit has a longer remaining life expectancy, such a facility should be incented to over control the newer unit. Yet, Equation 1 may block the facility from taking advantage of the emission averaging flexibility, especially if the older unit has a comparable or even higher rated capacity than the newer unit.

Response: See response to EPA-HQ-OAR-2002-0058-2808.1, excerpt 30 for the discount factor. The maximum rated heat input capacity was also used in the vacated rule in order to ensure adequate protection of the environment. Most of the commenters requesting for use of the actual instead of maximum rated heat input capacity were concerned with limited use units which have now been addressed using a separate subcategory. EPA does not agree that the intent of the MACT program is to allow infrequently used, but older coal units to participate in emissions averaging unless they can demonstrate that under maximum operating conditions the unit can meet the emission limit under the emissions averaging provision.

Commenter Name: Stephen R. Gossett
Commenter Affiliation: Eastman Chemical Company
Document Control Number: EPA-HQ-OAR-2002-0058-3137.1
Comment Excerpt Number: 6

Comment: Compliance on a monthly basis during the first twelve months of compliance period is unworkable.

Proposed §63.7522(f)(3) requires a facility to generate enough credits to offset the debits each and every calendar month up until 12 months are accumulated and, thereafter, determine compliance on a twelve month rolling average basis. This requirement unnecessarily restricts the utility of the emission averaging provision. For example, in the case where a facility over-controls one boiler while under-controlling the other, there will be months when the facility could not comply. This would certainly be true during a month when the credit-generating unit is down for its periodic maintenance outage. Due to the necessary length of these outages (4-6 weeks), there could conceivably be two or three months in a row where the facility could not comply with proposed averaging provisions. There will be other cases where the credit-generating unit experiences an unanticipated outage and the debit-generating unit is required to operate more to compensate. For these reasons, this provision should be eliminated. Eastman notes that the HON, which EPA references, includes an annual emission test along with a quarterly emission test where the average emissions must be less than 130 percent of the allowable emissions. Here, EPA acknowledges that a short term average (quarterly) must provide some tolerance as compared to an annual average. We bring this point up, not to suggest to EPA to adopt the HON quarterly test, but to illustrate that EPA emissions averaging provisions have accounted for this issue. Also, we would note that the HON is written for an entirely different industry than the case of boilers and process heaters. Due to the circumstances described above (extended outages while other units take on additional load), a facility using emissions averaging for boilers and process heaters should be subject to only annual compliance determinations.

Response: See response to EPA-HQ-OAR-2002-0058-2824.1, excerpt 23 for response to comment on timing of first compliance demonstration.

Commenter Name: Stephen R. Gossett
Commenter Affiliation: Eastman Chemical Company
Document Control Number: EPA-HQ-OAR-2002-0058-3137.1
Comment Excerpt Number: 7

Comment: The 10 percent penalty for using emissions averaging is arbitrary, unnecessary, and should be removed.

First, it appears the 10 percent discount factor discussed on page 32035 of the proposed rule should be in the denominator in Equations 1 – 4. EPA solicits comment on this discount factor and states that its inclusion further ensures the allowable emissions are at least as stringent as the MACT floor limits without using averaging. Given the accuracy of heat input weighted emission calculations, Eastman does not see that there is any uncertainty that the average emission rates will be any less stringent than when not using averaging. This discount factor is arbitrary and should be eliminated. Its inclusion reduces the flexibility the averaging concept provides.

Response: See response to EPA-HQ-OAR-2002-0058-2808.1, excerpt 30 for the discount factor.

Commenter Name: Myra C. Reece
Commenter Affiliation: South Carolina Department of Health and Environmental Control
Document Control Number: EPA-HQ-OAR-2002-0058-2525.1
Comment Excerpt Number: 7

Comment: The EPA proposes that "for each existing boiler or process heater in the averaging group, 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 the date 30 days after publication of the final rule in the federal register 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 the date 30 days after publication of the final rule in the federal register (75FR 32053)." The EPA reasons that these "caps would ensure that emissions do not increase above the emission levels that sources currently are designed, operated, and maintained to achieve" (75FR 32034).

In order to enforce and implement the cap requirement, the EPA proposes to require facilities choosing to demonstrate compliance by the emission averaging option to submit an "implementation plan" for review and approval by the delegated authority. Additionally, in section IV.L of the preamble of the proposed rule, the EPA recognizes that it "must ensure that any emissions averaging option can be implemented and enforced" and "will be clear to sources" (75FR 32034); however, the EPA did not provide a clear process for implementing and enforcing this complex compliance option.

Emission Caps For Existing Affected Sources Choosing To Demonstrate Compliance By The Emission Averaging Option Cannot Be Effectively Implemented Or Enforced. The Emission Cap Should Be Included In The Compliance Calculations

We believe that the requirement to establish an emission cap and submit an implementation plan to the permitting agencies for approval is problematic as written. Because the emission cap is not used in the initial compliance demonstration or in demonstrating continuous compliance with the emission averaging option, it is of little use.

If the intent of this option is for facilities to not exceed the cap at any time, then a demonstration methodology showing that the cap is not being exceeded needs to be included in the compliance equations in 63.7522. If the cap is included in the compliance equations, facilities could certify compliance with the cap in the notice of compliance status (NOCS) and within each required semiannual report. Additionally, 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 plans.

We received several implementation plans from facilities trying to comply with the vacated Boiler MACT rule in 2007. We encountered many problems with the approval process and received little help and guidance from the EPA. The EPA used the same approval process in the new proposed Boiler MACT rule disregarding the known problems states faced trying to implement the vacated rule in 2007.

Response: See response to EPA-HQ-OAR-2002-0058-3213.1, excerpt 180 for response to comment on timing of first compliance demonstration.
We have included an item in the notification of compliance status to report the control devices employed or emissions levels being achieved 60 days after publication in the federal register. We have also included a new certification item in the ongoing compliance reports to certify that the the current control device configuration or emissions levels being achieved are no less stringent than the control devices employed or emissions levels being achieved 60 days after publication in the federal register. These items will help aid delegated authorities in determining compliance with the emissions averaging provisions. However, EPA also determined that given the complexity of the emissions averaging, the emissions averaging implementation plan is still a required report that should be submitted and approved by the relevant delegated authority. The final rule includes criteria to help guide delegated authorities in the criteria used to review and approve each reports.

Commenter Name: Michael Bradley
Commenter Affiliation: The Clean Energy Group
Document Control Number: EPA-HQ-OAR-2002-0058-2466.1
Comment Excerpt Number: 8

Comment: The Clean Energy Group supports EPA's efforts to allow emissions averaging for ICI boilers,
recognizing the smaller nature of the source category and the need for regulatory flexibility. As EPA noted in the preamble, emissions averaging provides sources the flexibility to comply in the least costly manner while maintaining workable and enforceable regulation. Because emissions averaging represents an equivalent, more flexible, and less costly alternative for many units, we agree with EPA that the averaging proposed in this rule would likely result in cost and energy savings to owners and operators. Additionally, we agree that the proposal meets the Clean Air Act's requirements and EPA's previous policies regarding the scope and nature of emissions averaging programs.

Response: EPA acknowledges support of the emission averaging provision and has retained the emission averaging provision in the final rule.

Commenter Name: Michael Bradley
Commenter Affiliation: The Clean Energy Group
Document Control Number: EPA-HQ-OAR-2002-0058-2466.1
Comment Excerpt Number: 9

Comment: We disagree with EPA's use of a discount factor. This appears to be in contrast to the majority of previous EPA rulemakings that have demonstrated the cost-efficiency and environmental efficacy of averaging provisions, such as those proposed here for the same pollutants at the same facility. The standard monitoring provisions included in this rule are sufficient to ensure compliance with the standards. In addition, there does not seem to be a legal basis for this provision, as it would be arbitrarily increasing emissions reduction requirements beyond both the MACT floor and the identified "beyond-the-floor" reductions. The discount factor would create substantial administrative burdens without any clear environmental, legal, or policy benefits.

Response: See response to EPA-HQ-OAR-2002-0058-2808.1, excerpt 30 for the discount factor.

Commenter Name: G. Vinson Hellwig and Robert H. Colby
Commenter Affiliation: National Assocation of Clean Air Agencies
Document Control Number: EPA-HQ-OAR-2002-0058-2841.1
Comment Excerpt Number: 33

Comment: Emission averaging within a source can be an effective means of reducing compliance costs to the source without adversely impacting public health. NACAA generally supports the concept of emission averaging as set out in the proposal provided: (1) there is clear authority to do so under section 112 and (2) the benefits of averaging are fairly apportioned between the regulated community and the public. While emission averaging is helpful to sources on the margin, it should not be adopted if it will cause significant risk that the final rule will be overturned. Where a source is able to achieve more cost-effective emission reductions at one unit, emission averaging offers a "win-win" opportunity that should be embraced without penalty to the source. However, at times, compliance costs are reduced, at least in part, because sources are able to emit more of the regulated pollutant than without emission averaging because they can operate with smaller compliance margins. EPA has solicited comment on whether a 10-percent reduction in the overall emission limit would be appropriate if averaging were allowed, but has offered no estimate on how much of an emissions increase would result from averaging. If the units at issue indeed have the 300-percent to 1000-percent variability that EPA's MACT floor analysis suggests, a 10-percent penalty would seem to allow a fairly significant increase in overall emissions at the source. The increase in emissions could be evaluated by calculating how much the variability is decreased[Presumably, this calculation would be a variation of EPA's determination of the Upper Probability Limit, given the variability of the units and the number of tests needed to show compliance.] when paired compliance demonstrations are to be made. It may be that this issue can also be addressed by appropriate corrections to the MACT variability analysis and compliance demonstration provisions.

Response: See response to EPA-HQ-OAR-2002-0058-2808.1, excerpt 30 for the discount factor. Regarding re-analysis of the impact a discount factor would have on the emissions impacts associated with this rule making, EPA does not have the data in hand to quantitatively assess how the incorporation or removal of a discount factor would affect the compliance margins a source operates with. EPA has identified that including a discount factor will provide additional compliance flexibilities to a limited subset of units that are consistently below the emission limits.

Commenter Name: Britt S. Fleming
Commenter Affiliation: Auto Group
Document Control Number: EPA-HQ-OAR-2002-0058-2775.1
Comment Excerpt Number: 47

Comment: The proposed emission averaging is explained as allowing averaging only within a subcategory [Footnote: See 75 Fed. Reg. at 32,024.] although it is not clear from the proposed rule language if this is what EPA intended. [Footnote: See 75 Fed. Reg. at 32,053 (proposed § 63.7522(a)).] While the wording under the separate stack requirements does seem to have this restriction, the wording under the common stack requirements does not. [Footnote: See 75 Fed. Reg. at 32,055 (Equation 6).] EPA provides no justification for restricting averaging to a given subcategory nor is it rational to impose such a restriction.

Some affected units involve multiple boilers operating in different subcategories (e.g. stokers and pulverized coal). These boilers are generally located in separate powerhouses. The goal of emissions averaging is to allow facilities to over control some emissions points while under controlling others, thus achieving the required reductions in the most cost-effective manner possible. This could be best achieved by EPA removing the restriction (or clarifying its intent) that such averaging would be allowed for all affected units, regardless of whether the boilers emit through separate or "common stacks." The rule should allow for averaging across all units regardless of category of pollutants to be averaged so long as emissions from a single unit can be quantified with testing either in the breeching or in the stack when other units are not operating. Allowing averaging across subcategories within the rule is consistent with the four averaging criteria described in the preamble:

(1) No averaging between different types of pollutants;
(2) No averaging between sources that are not part of the same affected source;
(3) No averaging between individual sources within a single major source if the individual sources are not subject to the same NESHAP; and
(4) No averaging between existing sources and new sources. [Footnote: See 75 Fed. Reg. at 32,035.] Thus, averaging across subcategories is a possible interpretation of the proposal, and EPA should revise this in the final rule.

EPA provides no justification for restricting averaging to a given subcategory nor is it rational to impose such a restriction. Emissions averaging generally allows a facility to avoid otherwise cost-prohibitive compliance options by over-controlling some other emission unit in a more cost-effective combination. It also has corresponding environmental benefits, by creating an incentive to burn more natural gas or renewable fuels as a strategy to average out emissions from a coal-fired unit. If the proposed Boiler MACT does not allow averaging across the different fuel categories, EPA removes the incentive for sources to turn to cleaner-burning fuels to achieve averaging benefits.

The legal precursor to introducing emissions averaging is Chevron U.S.A., Inc. v. NRDC. [Footnote: 467 U.S. 837 (1984).] In Chevron, the Supreme Court held that EPA regulations allowing states to treat all of the pollution-emitting devices within the same industrial grouping as though they were encased within a single "bubble" were based on a reasonable construction by EPA. This case opened the door to more specific emissions averaging efforts, such as those implemented in the 1994 Hazardous Organic NESHAP (HON Rule). [Footnote: 59 Fed. Reg. 19,402, 19,425 (Apr. 22, 1994).] Several rules have followed the HON Rule in authorizing emissions averaging, and the D.C. Circuit has never invalidated the approach. The proposed emissions averaging provisions in the proposed Boiler MACT are directly based on the emissions averaging provisions in the HON.
In the HON Rule, EPA thoroughly examined the legal basis for emissions averaging, and explored the degree of averaging permitted under section112(d) of the CAA. At the end of its review, EPA concluded that the statute "does not define source category, nor does it impose precise limits on the Administrator's discretion to define source." [Footnote: 59 Fed. Reg. 19,402, 19,425 (Apr. 22, 1994).] EPA further acknowledged that the CAA does not limit how standards are to be set for a category or subcategory beyond requiring that it be applicable to all sources in a category, be written as a numerical limit wherever feasible, and be at least as stringent as the floor. [Footnote: 59 Fed. Reg. 19,402, 19,425 (Apr. 22, 1994).]

In promulgating the HON emissions averaging requirements, on which the proposed Boiler MACT relies, EPA thus concluded that "the relevant statutory language is broad enough to permit the Administrator to allow sources to meet the MACT through the use of emissions averaging provided the standard applies to every source in the category, averaging does not cross source boundaries, and the standard is no less stringent than the floor." [Footnote: 59 Fed. Reg. 19,402, 19,425 (Apr. 22, 1994).] Allowing emissions averaging across subcategories within the proposed Boiler MACT is consistent with the parameters established in the HON rule, and reiterated in the preamble for the proposed Boiler MACT. [Footnote: See 75 Fed. Reg. at 32,035.] Namely, allowing averaging across subcategories will not result in averaging between (a) different types of pollutants, (b) sources that are not part of the same affected source, (c) individual sources within a single major source if the individual sources are not subject to the same NESHAP, and (d) existing sources and new sources. [Footnote: See 75 Fed. Reg. at 32,035.]

There is precedent in other MACT standards for allowing averaging across different types of units of a single source. For example, the HON rule allows process vents, storage vessels, transfer racks, and wastewater streams to all be included in an emission average across an affected source. [Footnote: See 40 C.F.R. Part 63, Subpart G.] EPA reasoned that averaging needed to be allowed across all emission points (except equipment leaks) in order to provide as much flexibility as possible while maintaining an enforceable emission limitation. [Footnote: 59 Fed. Reg. at 19,425.] Similar mechanisms have been adopted in other MACT standards such as the Petroleum Refinery NESHAP and the Boat Manufacturing NESHAP.[Footnote: See Petroleum Refinery NESHAP, 60 Fed. Reg. 43,244, 43,254 (Aug. 18, 1995) (allowing wide range of emission sources to be averaged, noting that "EPA has the flexibility to allow trading within a facility that includes units in different source categories"); Boat Manufacturing NESHAP, 66 Fed. Reg. 44,218, 44,232 (Aug. 22, 2001).]

As in the HON, the compliance methodology can easily accommodate subcategories with different emission limits for a given pollutant. This is done basically by calculating a weighted average allowable mass emission and a weighted average actual mass emission each month using heat inputs or steam production for each unit.

Response: See response to comment EPA-HQ-OAR-2002-0058-3213.1, excerpt 175 for response on averaging across different subcategories.
See response to comment EPA-HQ-OAR-2002-0058-2702.1, excerpt 205 for discussion of the legal case Chevron U.S.A., Inc. v. NRDC.

Commenter Name: Britt S. Fleming
Commenter Affiliation: Auto Group
Document Control Number: EPA-HQ-OAR-2002-0058-2775.1
Comment Excerpt Number: 48

Comment: Averaging across subcategories also should be permitted for dioxins/furans and carbon monoxide. A source should be allowed to comply with the dioxin/furan (D/F) standard via emission averaging. While it may not be appropriate to set numerical emission standards for D/F, if the final rule does include such numerical standards, a source with multiple units could choose to comply by installing a post-combustion control to reduce D/F on some units at a facility.

Additionally, carbon monoxide should be included in the emissions averaging provision, since some units may be able to easily meet the proposed CO limits, while, for others, it may impossible. To facilitate its inclusion, the emission limitation for CO should be expressed in an alternative form – lb/mmBtu. For the case of units using CEMs to measure CO, precedent exists for this as well, in the emission averaging provision for NOx found at 40 C.F.R. § 76.11. Heat input should be allowed to be determined using either flow monitors (some units subject to the NOx budget trading program have these already) or using fuel factors and diluent monitors per 40 C.F.R. Part 60, Method 19.

Response: See response to comment EPA-HQ-OAR-2002-0058-2801.1, excerpt 36 for discussion of pollutants eligible for emissions averaging.

Commenter Name: Britt S. Fleming
Commenter Affiliation: Auto Group
Document Control Number: EPA-HQ-OAR-2002-0058-2775.1
Comment Excerpt Number: 49

Comment: EPA also imposes a restriction that requires facilities using that option to meet a standard that is 10% stricter than the otherwise applicable limits. Footnote: See 75 Fed. Reg. at

32,035.] EPA should remove this 10% penalty for using emissions averaging because it is arbitrary, unnecessary for environmental protection and reduces the flexibility that averaging provides. EPA asserts that its inclusion further ensures the allowable emissions are at least as stringent as the MACT floor limits without using averaging. However, EPA offers no demonstration of this in the proposal. Given the accuracy of heat input weighted emission calculations, there is no uncertainty that the average emission rates will be any less stringent than when not using averaging. Because EPA already has determined that the standards in the proposed rule achieve the maximum emission reduction achievable for health and environmental protection, to require an additional 10% reduction of emissions has no basis in the environmental underpinnings of the rule. Given that emissions averaging is a compliance alternative, the 10% discount factor constitutes a beyond-the-floor requirement that EPA has not analyzed for its cost, non-air quality and energy impacts, as required by CAA section 112(d)(2). Finally, although the 10% discount may be perceived as a fair “trade-off” for the flexibility of emissions averaging, it still lacks a legal basis and creates a disincentive for sources to use this compliance method. Because the proposed limits in this rule already are so stringent, sources will not be able to ensure an additional 10% reduction in emissions below the limits and imposing this requirement effectively deprives many sources of the availability of the emissions averaging compliance alternative. For these reasons, EPA should delete the 10% discount in the final rule.

Response: See response to EPA-HQ-OAR-2002-0058-2808.1, excerpt 30 for the discount factor.

Commenter Name: Britt S. Fleming
Commenter Affiliation: Auto Group
Document Control Number: EPA-HQ-OAR-2002-0058-2775.1
Comment Excerpt Number: 63

Comment: Proposed § 63.7522 – The requirements in subsection (c) are unclear in that this provision appears to limit the emission rate demonstrated during the initial compliance test to the emission level that was achieved 30 days after the final rule is published in the Federal Register. This contradicts other parts of the proposed rule where a facility is allowed to burn multiple fuels during the initial compliance test to demonstrate compliance with different fuels. One of the fuels demonstrated may be higher in a particular HAP than what occurred 30 days after publishing in the Federal Register and yet be in compliance with the MACT standard.

Response: See response to comment EPA-HQ-OAR-2002-0058-2960.1, excerpt 228 for clarification of the anti-backsliding procedures.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 175

Comment: EPA Should Incorporate Additional Flexibility into the Emissions Averaging Provisions

We agree that incorporating emissions averaging into the Boiler MACT is a proper way to encourage flexibility and cost savings for affected facilities. There is ample precedent in the MACT program for allowing emissions averaging. For example, the Pulp and Paper Chemical Recovery Combustion MACT allows plants to set a PM HAP emissions limit for each existing applicable process unit such that, if these limits are met, the total emissions from all existing process units are less than or equal to a "bubble" limit on all affected units. See 66 Fed. Reg. 3180, 3184 (January 13, 2001) and 40 C.F.R. Part 63, Subpart MM. See also 67 Fed. Reg. 78046 (December 20, 2002) (proposing emissions averaging in the Lime Manufacturing MACT). Many other MACT standards have included emissions averaging provisions, which are conceptually similar. See, e.g., 40 C.F.R. Part 63, Subpart JJJ (Group IV Polymers and Resins); 40 C.F.R. Part 63, Subpart U (Group I Polymers and Resins); 40 C.F.R. Part 63, Subpart G (Synthetic Organic Chemical Manufacturing Industry: Process Vents, Storage Vessels, Transfer Operations and Wastewater); 40 C.F.R. Part 63, Subpart LL (Primary Aluminum Reduction Plants); 40 C.F.R. Part 63, Subpart CC (Petroleum Refineries); 40 C.F.R. Part 63, Subpart EEE (Hazardous Waste Combustors).

Emissions averaging is a well demonstrated technique for meeting or exceeding environmental objectives at lower cost and with greater flexibility tailored to individual affected facilities. Provisions such as these allow plants to optimize their investments by installing controls on units where the lowest emission rates can be achieved in the most cost-effective manner possible. For example, a source could decide to over-control a newer unit in order to avoid costly investments in an older unit that may be retired before the useful life of the control device is reached. Emissions averaging provisions also provide environmental benefit by allowing for control options that minimize energy use. Energy efficient decisions benefit the environment by reducing power demands and the secondary pollutant impacts they generate.

AF&PA concurs with EPA's proposal and past precedent that use of the emissions averaging compliance alternative would be limited to existing units. New and reconstructed boilers/process heaters would be required to meet the more stringent "new source" requirements.

However, we believe that additional flexibility should be incorporated into the proposed emissions averaging provisions in order to ensure facilities have options to reduce the cost of compliance. The emissions averaging provisions should be based on actual operating time and emissions and not capacity. Adding the element of time ensures equivalent control regardless of boiler operating schedules and provides flexibility with respect to the control strategy for limited use boilers. Some boilers are only used during maintenance outages, and incorporating flexibility into the emissions averaging provisions to accommodate limited use boilers will greatly reduce the compliance cost for these boilers. Boilers sharing common stacks should also be eligible for inclusion in the emissions averaging approach, especially if emissions can be measured from each boiler prior to the common stack. EPA has included all common stack units in its MACT floor analyses by applying the measured common emission rate to each unit, instead of one time for the group of units, so this approach could also be used in an emissions averaging compliance scenario.

Response: While EPA did not make major adjustments to the emissions averaging provisions, the change to a solid fuel subcategory will enable all solid fuel-fired units at a facility to use the emissions averaging provision for Hg, PM, and HCl. Beyond this, EPA disagrees that it is appropriate to average across subcategories for affected sources with mixed streams (e.g., SOCMI) and the commenter does not provide sufficient justification for swaying from this precedent.

See response to comment EPA-HQ-OAR-2002-0058-2694.1, excerpt 3, for response to actual vs. rated heat input capacity and a discussion of how units with common stacks can participate in the emisisons averaging provision.

EPA acknowledges the support of past precedent and has retained the prohibitions of the emission averaging provisions for new sources.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 176

Comment: In addition, AF&PA believes that boilers of any design firing any fuel (e.g., in any subcategory) should be included in the emissions averaging provisions and that facilities should not be limited to use of emissions averaging only for boilers in the same subcategory. There is no justification for restricting emissions averaging only to boilers in a specific subcategory; facilities should be able to average emissions from stoker boilers with emissions from pulverized coal boilers and liquid boilers. This approach has been used in several of the other rules mentioned above. For example, the Pulp and Paper Chemical Recovery Combustion MACT and the HON allow emissions averaging across different types of units. The equivalency by permit provisions under 40 CFR 63.94 allow sources to “trade” emissions from unregulated sources for emissions of regulated sources, so this is additional reason not to restrict use of emissions averaging to boilers within the same subcategory.

Response: See response to comment EPA-HQ-OAR-2002-0058-3213.1, excerpt 175 for emission averaging between subcategories.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 177

Comment: We also disagree that a 10 percent penalty for use of emissions averaging is appropriate. This requirement restricts the utility of the proposed emissions averaging provisions, especially as this demonstration is proposed to be based on unit capacity and not actual unit operating data. The Pulp and Paper Chemical Recovery Combustion MACT allows averaging of emissions with no requirement to further reduce emissions to 90 percent of the allowable emission rate.

We believe that the application of the underlying principles of emissions averaging, as stated in the Proposed Rule, is sufficient to ensure full realization of the statutory requirements of meeting the MACT standards for the affected sources and that no discount factor is required. EPA fails to justify the necessity to further tighten emissions standards when emissions averaging is used. This point is further reinforced by the fact that EPA expressly excluded the provisions of emissions averaging, including the discount factor, to a situation where individual units are vented through a common stack. EPA must realize that there is no difference in actual emissions between two units emitting from separate stacks and the same units, operated in an identical fashion, emitting from a common stack: the quantity of contaminants emitted to the atmosphere will be identical in both circumstances and imposing a discount factor to the units emitting separately will surely discourage any facility from using this compliance option.

Response: See response to EPA-HQ-OAR-2002-0058-2808.1, excerpt 30 for the discount factor.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 178

Comment: EPA bases its justification for including of a discount factor on the emissions averaging provisions in the Hazardous Organic NESHAP (HON), stating that the legal basis and rational for the HON emissions averaging provisions have been provided in the preamble to the final HON. However, EPA dismisses this discount provision in the preamble to the proposed NESHAP rule for Plywood and Composite Wood Products (PCWP MACT), stating "…(the) HON sources have many emission points, are complex and diverse, and as a result are subject to a more complex set of emissions averaging provisions. The PCWP facilities have fewer emission points within each facility. Therefore, the enforcement concerns arising due to the large number of emission points in each HON facility are minimized for PCWP facilities." EPA concludes its argument to dismissing a discount factor for PCWP sources by stating that "…(the) HON requires a discount factor of 10 percent in credit calculations to share with the environment some portion of the cost savings due to emissions averaging and to account for uncertainty in emissions estimation. Due to differences between PCWP and HON sources (discussed below), we do not believe it is necessary for the proposed PCWP rule to include a discount factor.". This conclusion was maintained in the final version of the PCWP MACT Rule. In fact, the concept of imposing a discount factor on the use of emissions averaging was never discussed neither in the initially proposed nor the previous final Boiler MACT Rule. Hence we believe that imposing a discount factor to the emissions averaging compliance alternative is unwarranted and unjustified.

Response: See response to EPA-HQ-OAR-2002-0058-2808.1, excerpt 30 for the discount factor.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)

Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 179

Comment: AF&PA recommends that sources be given the flexibility to use emissions averaging provisions or include alternative emission limits for dioxin as well as for PM/TSM, HCl, and mercury. For dioxin, which is a concentration based limit and not a mass based limit, the source would calculate its recommended alternative emission limits using an approach similar to that included in the Pulp and Paper Chemical Recovery Combustion MACT for the PM limits in gr/dscf, and these emission limits would be submitted to the permitting authority for approval and inclusion in the air permit. The alternative emission limits would be set during the initial compliance test. Separate alternative emission limit calculations could be submitted for PM HAP, total metals, mercury and/or HCl at the discretion of the applicant. A site's emissions averaging plan need not include all pollutants; and for any pollutants not specifically included in the emissions averaging plan, the Rule's emissions limitations would apply as a default.
See submittal for equation that could be used to define this averaging methodology:

Response: See response to comment EPA-HQ-OAR-2002-0058-2801.1, excerpt 36 for discussion of pollutants eligible for emissions averaging.
See response to EPA-HQ-OAR-2002-0058-2694.1, excerpt 6 for developing site specific factor for dioxin/furan.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 180

Comment: The proposed rule contains a requirement for the facility to demonstrate each month that the average weighted emissions of the boilers included in the emissions averaging scheme are below the applicable emission limit using the actual heat inputs for that month. AF&PA believes that an annual determination that the emission limits under the emissions averaging approach are being met is more than satisfactory to ensure protection of public health and welfare and appropriate for consideration for a technology-based MACT standard. The first compliance demonstration should not be required immediately after the rule compliance date, as maintenance and outage schedules may make it hard for a facility to comply with the emissions averaging provisions without 12 full months of data. Other rules do not require a monthly test (e.g., the HON), but provide a 30 percent allowance during each quarter and equivalency on an annual basis. Although a year is an appropriate period for determining the time-weighted average emissions rate, consideration may be given for convenience sake to a shorter 6 month period that coincides with the required reporting period for the standard. It is expected that a 6 to 12 month period would provide the flexibility needed to retain the benefit of the recommended averaging provisions.

Response: EPA acknowledges the concerns of the commenter, however the current rule language provisions apply to monthly compliance determinations and are not workable under a different period.

Commenter Name: Donald R. Schregardus
Commenter Affiliation: Department of Defense
Document Control Number: EPA-HQ-OAR-2002-0058-2763.1
Comment Excerpt Number: 16

Comment: In §IV.L. of the preamble, EPA solicited comments on the proposed emission averaging proposal. Specifically, EPA requested comments on the appropriateness of the discount factor and the provision that emission averaging can not be applied when boilers share a common stack.

DoD recognizes that offset ratios are appropriate for emission trading programs since there are different entities involved and de minimis levels below which no trading is required — the offset ratio in those programs helps compensate for the minor sources for which no offsets are required and helps to ensure that there is always an environmental benefit. In the proposed rule, there are no de minimis thresholds, not even small source or limited use exemptions; emission limits are required for all sources at a major source. As a result, the basis for requiring an offset ratio or discount factor does not apply — it should be sufficient to simply require that the emissions be no higher than the emissions without emission averaging.

Remove the discount factor from equations 1 through 4 of the proposed rule. It should be sufficient to simply require that the emissions are no higher for any pollutant when emission averaging than would be required without emission averaging.

Response: EPA disagrees with the commenter that all units at a major source are subject to emission limits and therefore the discount factor does not apply. Existing small units, limited use units, and units firing gas 1 fuels are not subject to numeric emission limits. See response to EPA-HQ-OAR-2002-0058-2808.1, excerpt 30 for the discount factor.

Commenter Name: Donald R. Schregardus
Commenter Affiliation: Department of Defense
Document Control Number: EPA-HQ-OAR-2002-0058-2763.1
Comment Excerpt Number: 17

Comment: DoD facilities tend to have excess capacity and it is not uncommon to have a completely redundant capacity with a different fuel source. This is prudent planning for military facilities and helps ensure that the facility is not vulnerable to sabotage or terrorist acts. With excess capacity, it is not uncommon for multiple boilers to share a common stack. Coal-fired boilers typically use a different fuel for start-up; either natural gas, oil or in the case of stoker boilers —wood. Facilities that use oil for start-up that would like to add a baghouse to control

particulate emissions or dry scrubber systems to control mercury and/or HC1, will most likely change the start-up fuel to natural gas so as to not blank the bags. A new natural gas system may be sufficient to meet demand and may, at times, be less expensive to operate than the coal system. Replacing fuel oil or coal operations with natural gas would reduce the toxic emissions from the facility so it would be advantageous to encourage these modifications. Requiring a separate stack and redundant ducting system, which would be necessary to route the flue gases to a separate stack during alternative fuel operations, would not further environmental aims. As long as the emissions can be individually measured and monitored there should be no need for the emissions to be from separate stacks.
The preamble states that "the emissions averaging provision would not apply to individual units if the unit shares a common stack with units in other subcategories, because in that circumstance it is not possible to distinguish the emissions from each individual unit." This may be true when units in different subcategories are operating at the same time and there is no way to measure individual unit emissions before they reach the common stack. Although the text of the rule does not appear to prevent averaging under all circumstances with units that share stacks with other subcategories, DoD wants to be sure EPA recognizes that units in this situation may still be able to participate in averaging when their emissions can be measured prior to reaching the common stack.

Ensure the final rule does not limit emissions averaging from common stacks shared by more than one subcategory as long as facilities have the capability to monitor emissions for individual units such as in the breeching or ducting leading to the common stack.

Response: See response to comment EPA-HQ-OAR-2002-0058-2694.1, excerpt 3, for how units with common stacks can participate in the emissions averaging provision.

Commenter Name: Chris Greissing
Commenter Affiliation: Industrial Minerals Association
Document Control Number: EPA-HQ-OAR-2002-0058-2740.2
Comment Excerpt Number: 21

Comment: EPA Fails to Justify the 10 percent Discount Factor for Emissions Averaging. The Proposed Rule 63.7522 allows existing sources to use emission averaging as an alternative compliance mechanism for PM, HCl, and Hg. The soda ash companies, all of whom have more than one unit, support EPA’s decision to allow emission averaging. However, EPA is requiring, for sources that use emissions averaging, the imposition of a 10 percent “discount factor.” 75 Fed. Reg. at 32035. There is no reasonable need or basis for this discount.

EPA’s only justification for the 10 percent discount factor is to “further ensure that averaging will be at least as stringent as the MACT floor limits in the absence of averaging.” Id. EPA provides no data that supports the implication of such statement; that averaging otherwise would allow facilities to emit more HAPs. That simply will not be the case. EPA notes that emissions averaging will only be available for those existing sources that demonstrate that the “total quantity of any particular HAP that may be emitted by that portion of a contiguous major source

. . . will not be great under the averaging mechanism than it could be if each individual affected unit complied separately with the applicable standard.” 75 Fed. Reg. at 32034. EPA continues that this requirement will ensure equivalence to compliance with the MACT floor by “each discrete unit.” Id. By definition, therefore, averaged emissions must be at least as stringent as MACT floor limits in the absence of averaging. Accordingly, there is no reason to impose a 10 percent discount factor on facilities that qualify for emissions averaging, and it should be eliminated.

Response: See response to EPA-HQ-OAR-2002-0058-2808.1, excerpt 30 for the discount factor.

Commenter Name: Melvin E. Keener
Commenter Affiliation: Coalition for Responsible Waste Incineration (CRWI)
Document Control Number: EPA-HQ-OAR-2002-0058-2824.1
Comment Excerpt Number: 23

Comment: CRWI supports inclusion of the emission averaging provisions but revisions are needed to expand and improve the usefulness of these provisions.

A. Dioxins/furans should be included.

A source should be allowed to comply with the dioxin/furan (D/F) standard via emission averaging. While CRWI does not believe it is appropriate to set numerical emission standards for D/F, if the final rule does include such numerical standards, a source with multiple units could choose to comply by installing post-combustion control (such as activated carbon injection) to reduce D/Fs on some units. (Note: this example does not imply CRWI believes such technology has been demonstrated on industrial boilers). Since that pollution reduction strategy would justify allowing use of emission averaging for other HAPs, sources should be allowed the same flexibility for dioxins/furans in order to reduce the overall compliance costs for the facility.

B. Carbon monoxide should be included.

Some units may be able to easily meet the proposed CO limits, while, for others, it may impossible. Therefore, CO should be included in the emissions averaging provisions. To facilitate its inclusion, the emission limitation for CO should be expressed in an alternative form — lb/mmBtu. For the case of units using CEMS to measure CO, we reference an existing emission averaging provision for NOx found at 40 CFR 76.11. Heat input should be allowed to be determined using either flow monitors (some units subject to the NOx budget trading program have these already) or using fuel factors and diluent monitors per 40 CFR 60 Method 19.

C. Averaging across subcategories should be allowed.

The proposed emission averaging provision appears to only allow averaging within a subcategory (see 63.7522(a). CRWI believes there is no justification for restricting averaging to a given subcategory. Other MACT standards do not place such restrictions. For example, the

Hazardous Organic NESHAP (40 CFR 63 Subpart G) allows process vents, storage vessels, transfer racks, and wastewater streams to all be included in an emission average across an affected source. This provides a facility the opportunity to avoid otherwise, cost-prohibitive compliance options by over-controlling some other emission unit in a more cost-effective combination. In addition, by not allowing averaging across the different fuel types, EPA removes an incentive to burn more natural gas or renewable fuels such as biomass as a strategy to average out emissions from a coal-fired unit.

It is not clear from the proposed rule language if EPA intended to restrict averaging across subcategories. While the wording under the separate stack requirements seems to have this restriction, the wording under the common stack requirements does not (see Equation 6). In any event, as ‘stated above, there should be no such restriction.

As in the HON, the compliance methodology can easily accommodate subcategories with different emission limits for a given pollutant. This is’ done basically by calculating a weighted average allowable mass emission and a weighted average actual mass emission each month using heat inputs or steam production for each unit.

Compliance should be based solely on actual emissions:

The proposed provisions require (1) a demonstration that the average weighted emissions is Tess than 90 percent of the applicable emissions limit assuming each unit is operating at its maximum rated heat input capacity (see Equation 1) and (2) a demonstration each calendar month that the average weighted emissions is less than the applicable emissions limit using the actual heat inputs for that month.

There is no rationale for the first test and it should be eliminated. Other rules that allow emission averaging (again, see the HON), include no such requirement. Such a requirement could be unduly restrictive. For example, a facility may have one older unit and a newer unit which they would like to average. The older unit may have a much lower capacity factor (ratio of actual usage divided by rated capacity) than the newer one. Older units typically have much more space constraints and a facility may be facing steep compliance costs to bring the older unit into compliance and may have an opportunity to over-control the newer unit. Given that the newer unit has a longer remaining life expectancy, such a facility should be incented to over control the newer unit. Yet, Equation 1 may block the facility from taking advantage of the emission averaging flexibility, especially if the older unit has a comparable or even higher rated capacity than the newer unit.

Compliance on a monthly basis during the first twelve months of compliance period is unworkable.

Proposed 63.7522(f)(3) requires a facility to generate enough credits to offset the debits each and every calendar month up until 12 months are accumulated and, thereafter, determine compliance on a twelve month rolling average basis. This requirement unnecessarily restricts the utility of the emission averaging provision. For example, in the case where a facility over-controls one boiler while under-controlling the other, there will be months when the facility could not comply with individual unit limits — even though the facility meets the emission limits on a "facility" basis. This would certainly be true during a month when the credit-generating unit is down for its periodic maintenance outage or during high heating demand months when both units are required at full capacity. Due to the necessary length of these outages (4-6 weeks); there could conceivably be two or three months in a row where the facility could not comply with proposed averaging provisions. There will be other cases where the credit-generating unit experiences an unanticipated outage and the debit-generating unit is required to operate more to compensate. For these reasons, this provision should be eliminated. CRWI notes that the HON, which EPA references, includes an annual emission test along with a quarterly emission test where the average emissions must be less than 130 percent of the allowable emissions. Here, EPA acknowledges that a short term average (quarterly) must provide some tolerance as compared to an annual average. We bring this point'up, not to suggest that EPA adopt the HON quarterly test, but to illustrate that EPA emissions averaging provisions have accounted for this issue. Also, we would note that the HON is written for an entirely different industry than the case of boilers and process heaters. Due to the circumstances described above (extended outages While other units take on additional load or during high heating demand months when both units are required at full capacity), a facility using emissions averaging for boilers and process heaters should be subject to only annual compliance determinations.

The 10 percent penalty for using emissions averaging is arbitrary, unnecessary, and should be removed.

EPA' solicits comment on this discount factor and states that its inclusion further ensures the allowable emissions are, at least as stringent as the MACT floor limits without using averaging. Given the accuracy of heat input weighted emission calculations, CRWI does not see that there is any uncertainty that the average emission rates will be any less stringent than when not using averaging. This discount factor is arbitrary and should be eliminated. Its inclusion reduces the flexibility that the averaging concept provides.

Response: EPA acknowledges the concerns of the commenter, however the current rule language provisions apply to monthly compliance determinations and are not workable under a different period.

Commenter Name: William A. Moore
Commenter Affiliation: Luminant
Document Control Number: EPA-HQ-OAR-2002-0058-2780.1
Comment Excerpt Number: 23

Comment: Luminant supports EPA's choice of emissions averaging as an alternative compliance approach. Luminant fully supports the flexibility EPA has provided in the proposed rule to allow emissions averaging. See 75 Fed. Reg. 32,006, 32,034 (June 4, 2010). This approach is reasonable in that it does not result in less stringent standards than the MACT floor limits, provides flexibility, and will reduce costs associated with compliance with the NESHAP.

Response: EPA acknowledges support of the emission averaging provision and has retained the emission averaging provision in the final rule.

Commenter Name: William A. Moore
Commenter Affiliation: Luminant
Document Control Number: EPA-HQ-OAR-2002-0058-2780.1
Comment Excerpt Number: 24

Comment: EPA's suggestion of a ten percent discount factor for sources relying on the emissions averaging approach is not supported. EPA does not explain why a discount factor of ten percent is needed. EPA has limited the scope and nature of emissions averaging to ensure that the standard is at least as stringent as the MACT floor. There is no reason for EPA to subject sources to an additional limitation and no public health benefit will be realized. Rather, the ten percent discount factor will ultimately act as a deterrent to emissions averaging. EPA should retain the emissions averaging provision but eliminate the ten percent discount factor.

Response: See response to EPA-HQ-OAR-2002-0058-2808.1, excerpt 30 for the discount factor.

Commenter Name: David A. Buff
Commenter Affiliation: Golder Associates Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2801.1
Comment Excerpt Number: 36

Comment: Proposed rule §63.7522 and the related explanation in the preamble present the case for being allowed to average PM, HCl, and Hg emissions. This provision is applauded, since it demonstrates an understanding that a multi-boiler, multi-stack facility may be able to achieve and maintain a facility standard as a combination of all stack emissions rather than by each stack individually.

We request that the averaging option extend to CO and D/F compliance. The rational for allowing a facility to average these constituents is the same as that used in the preamble for the other controlled emissions. Namely: "... averaging would not lessen the stringency of the MACT floor limits and would provide flexibility in compliance, cost, and energy savings to owners and operators...." We also agree that the total facility emissions on a pounds per million British thermal units (lb/MMBtu) basis from averaging should be no less stringent than if each unit achieved the MACT floor limits; we only request that CO and D/F be included in the averaging. There is no basis for excluding CO and D/F from emissions averaging, since emissions of these pollutants are directly correlated with HAPs emissions, and emissions averaging would not allow overall facility HAPs emissions to increase.

Response: In the final rule, EPA is requesting only a one-time dioxin/furan testing, and it has modified the CO emission limits and CO compliance mechanisms which are expected to reduce the compliance burden on regulated entities. Further, both CO and dioxin/furan emissions are formed through combustion and not and it is important for the Agency to promote good combustion on all units. Most of the limits are expected to be achieved with good combustion and combustion controls instead of add-on pollution controls and so the concerns with costs of compliance are less than those associated with PM, HCl, and Hg which often require add-on controls to be installed on individual units. In addition, the limits for CO and dioxin/furan in the final rule are established on a concentration (ppm) basis as opposed to a emission factor (lb/mmBtu) basis. As a result, the equations and procedures in the final rule are not applicable to these two pollutants.

Commenter Name: David A. Buff
Commenter Affiliation: Golder Associates Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2801.1
Comment Excerpt Number: 37

Comment: We request that EPA remove the 10 percent penalty and the stipulation that emissions be capped at the value 60 days after the final promulgation of this rule if a facility chooses to comply by the averaging method. The averaging option is attractive and provides an incentive for a facility to engineer creative new control and equipment improvements. If the 10 percent penalty and cap are dropped, overall HAP emissions control will not be less, but will be less costly.

Previously, emission averaging has applied to multi-emission point sources subject to the Hazardous Organic NESHAP (HON) rule in a commonly covered facility such as a petroleum refinery or chemical plant. This rule differs materially in the type of facility and the scope of coverage within a facility. This proposed rule only applies to industrial boilers and process heaters. Boilers and process heaters typically do not have multiple pieces of equipment, vessels, and vents from which to choose optimization of emission control to achieve reductions to reach a facility wide emission limit. Boilers and process heaters have one emission point per unit and sometimes only one emission point for two or more units. Thus, the opportunities for emission reductions via related process equipment and vents do not exist. The 10 percent discount for the averaging method offered by the proposed rule is inappropriate for this MACT.

The proposed penalty and emissions cap and not extending the option to all emission limited pollutants is a disincentive for industry to innovate cost-effective creative emissions reductions for those multi-boiler facilities that might otherwise consider averaging. They also would hold a facility that chooses it to a more stringent standard than its industry contemporaries. This constitutes a capricious, even though perhaps unintended, imposition of a limit beyond the MACT floor on a subset of affected facilities. It is arbitrarily punitive to those facilities that can use averaging and shrinks the number of facilities that might be able to use it; thereby adding unnecessary capital and operating costs.

Response: See response to EPA-HQ-OAR-2002-0058-2808.1, excerpt 30 for the discount factor. See response to comment EPA-HQ-OAR-2002-0058-2801.1, excerpt 36 for discussion of pollutants eligible for emissions averaging.

Commenter Name: David A. Buff
Commenter Affiliation: Golder Associates Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2801.1
Comment Excerpt Number: 38

Comment: The purpose of this rule is to set MACT standards for HAPs from industrial boilers and process heaters and require industry to meet them. Averaging will encourage customized, creative, and cost efficient techniques and technology for facilities to meet the proposed standards.
In summary:

Proposed equations should be based on actual emissions, and not maximum rated capacity
Additional flexibility reduces cost, especially in case of limited use boilers
Need to be able to use reduced stack testing frequency if using emissions averaging
Need to be able to use the PM CEMS data in averaging equation
Oppose performing monthly compliance for first 12 months

Response: EPA has retained the emission averaging provision in the final rule. See response to EPA-HQ-OAR-2002-0058-3213.1, excerpt 175 for additional flexibilities incorporated into the emissions averaging provision.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-2702.1
Comment Excerpt Number: 204

Comment: Emissions Averaging
CIBO supports inclusion of the emission averaging provisions in the Proposed Rule, but revisions are needed to expand and improve the usefulness of these provisions. 75 FR 32034. Use of emissions averaging would allow owners and operators of an affected source to demonstrate that the source complies with the proposed emission limits by averaging the emission from an individual affected unit that is emitting above the proposed emission limits with other affected units at the same facility that are emitting below the proposed emission limits. 75 FR 32034. EPA further acknowledges that "emissions averaging represents an equivalent, more flexible and less costly alternative to controlling certain emission points to MACT levels" and its application "would not lessen the stringency of the MACT floor limits and would provide flexibility in compliance, cost and energy savings to owners and operators." 75 FR 32034.

EPA has proposed that owners and operators of existing – but not new – affected sources be permitted to demonstrate compliance with the proposed emissions limitations by emissions averaging for units at the affected source that are within a single subcategory. 75 FR 32034.

Under this proposal, emissions averaging could only be used between boilers and process heaters in the same subcategory at a particular affected source. 75 FR 32034.

Response: EPA has retained the emission averaging provision in the final rule. See response to EPA-HQ-OAR-2002-0058-3213.1, excerpt 175 for additional flexibilities incorporated into the emissions averaging provision.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-2702.1
Comment Excerpt Number: 205

Comment: A. The rule should allow for averaging across all subcategories/fuels with emission limits for the pollutant to be averaged.
The proposed emission averaging is explained as allowing averaging only within a subcategory (75 FR 32024) although it is not clear from the Proposed Rule language if this is what EPA intended. See § 63.7522(a), 75 FR 32053. While the wording under the separate stack requirements does seem to have this restriction, the wording under the common stack requirements does not. See Equation 6, 75 FR 32,055. EPA provides no justification for restricting averaging to a given subcategory nor is it rational to impose such a restriction.

EPA states in the preamble that one of its limits on the scope of emissions averaging is to not allow averaging between sources that are not part of the same affected source. 75 FR 32034. In this case, EPA has elected to define the affected source in §63.7490(a)(1) as all units within a subcategory. We see no reason for EPA to use this definition. Rather all units at a given facility subject to the subpart should be collectively considered the "affected source". This is how EPA has defined the term in other rules with which we are familiar (e.g. the HON in Subpart F, Polymer and Resins 4 in Subpart JJJ, the MON in Subpart FFFF). The HON in particular we understand is the model EPA is using to guide its policy. By defining the term affected source as all chemical manufacturing process units (CMPUs) at a facility, the HON allows emissions averaging across CMPUs and across emission unit types (vents, storage vessels, transfer racks, wastewater stream). There is no reason in the boiler and process heater MACT for EPA to restrict the emissions averaging alternative as it has proposed. To do so, will prevent some facilities from taking advantage of the opportunity to avoid otherwise cost-prohibitive compliance options by over-controlling some other emission unit in a more cost-effective combination. Also, by not allowing averaging across the different fuel categories, EPA removes an incentive to burn more natural gas or renewable fuels such as biomass as a strategy to average out emissions from a coal-fired unit.

Some affected units involve multiple boilers operating in different subcategories (e.g. stokers and pulverized coal). These boilers are generally located in separate powerhouses. The goal of emissions averaging is to allow facilities to overcontrol some emissions points while undercontrolling others, thus achieving the required reductions in the most cost-effective manner possible. This could be best achieved by EPA removing the restriction (or clarifying its intent) that such averaging would be allowed for all affected units, regardless of whether the boilers emit through separate or "common stacks."

The legal precursor to introducing emissions averaging is Chevron U.S.A., Inc. v. NRDC, 467 U.S. 837 (1984). In Chevron, the Supreme Court held that EPA regulations allowing states to treat all of the pollution-emitting devices within the same industrial grouping as though they were encased within a single "bubble" were based on a reasonable construction by EPA. This case opened the door to more specific emissions averaging efforts, such as those implemented in the 1994 Hazardous Organic NESHAP, 59 FR 19,425 (April 22, 1994)(HON Rule). Several rules have followed the HON Rule in authorizing emissions averaging, and the D.C. Circuit has never invalidated the approach. it does not appear that any such authorizations have succumbed to legal challenge. The proposed emissions averaging provisions in the Boiler Rule are directly based on the emissions averaging provisions in the HON.

In the HON Rule, EPA thoroughly examined the legal basis for emissions averaging, and explored the degree of averaging permitted under §112(d) of the Clean Air Act. At the end of its review, EPA concluded that the Clean Air Act "does not define source category, nor does it impose precise limits on the Administrator's discretion to define source." Id. EPA further acknowledged that the Clean Air Act does not limit how standards are to be set for a category or subcategory beyond requiring that it be applicable to all sources in a category, be written as a numerical limit wherever feasible, and be at least as stringent as the floor. Id.

In promulgating the HON emissions averaging rules, on which the Boiler Rule relies, EPA thus concluded that "the relevant statutory language is broad enough to permit the Administrator to allow sources to meet the MACT through the use of emissions averaging provided the standard applies to every source in the category, averaging does not cross source boundaries, and the standard is no less stringent than the floor." Id. Allowing emissions averaging across subcategories within the Boiler Rule is consistent with the parameters established in the HON rule, and reiterated in the Boiler Rule preamble. See 75 FR at 32,035. Namely, allowing averaging across subcategories will not result in averaging between (a) different types of pollutants, (b) sources that are not part of the same affected source (see other comments above regarding EPA's proposed definition of affected source), (c) individual sources within a single major source if the individual sources are not subject to the same NESHAP, and (d) existing sources and new sources. Id.

There is precedent in MACT standards for allowing averaging across different types of units of a single source. For example, the HON rule allows process vents, storage vessels, transfer racks, and wastewater streams to all be included in an emission average across an affected source. 40 CFR Subpart G. EPA reasoned that averaging needed to be allowed across all emission points (except equipment leaks) in order to provide as much flexibility as possible while maintaining an enforceable emission limitation. 59 FR 19,425. Similar mechanisms have been adopted in other

MACT standards. See, e.g. Petroleum Refinery NESHAP, 60 FR 43244, 43254 (Aug. 18, 1995)(allowing wide range of emission sources to be averaged, noting that "EPA has the flexibility to allow trading within a facility that includes units in different source categories"); Boat Manufacturing NESHAP, 66 FR 44,218; 44,232 (Aug. 22, 2001).

As in the HON, the compliance methodology can easily accommodate subcategories with different emission limits for a given pollutant. This is done basically by calculating a weighted average allowable mass emission and a weighted average actual mass emission each month using heat inputs or steam production for each unit.

Response: See response to comment EPA-HQ-OAR-2002-0058-3213.1, excerpt 175 for emission averaging between subcatgories.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-2702.1
Comment Excerpt Number: 206

Comment: B. The rule should allow for averaging dioxins/furans (D/Fs) and carbon monoxide. The same legal rationale that supports averaging across subcategories, also fully supports emissions averaging for various HAPs. The same policy rationale applies as well: sources should be allowed the flexibility to over-control at some units at a facility and under-control at others in order to reduce the overall compliance costs for the facility, where no increased risk to the environment results. Allowing this averaging is also consistent with the four averaging criteria described in the preamble.

Averaging across subcategories should be permitted for dioxins/furans and carbon monoxide. A source should be allowed to comply with the dioxin/furan (D/F) standard via emission averaging. While it may not be appropriate to set numerical emission standards for D/F, if the final rule does include such numerical standards, a source with multiple units could choose to comply by installing a post-combustion control (such as powder activated carbon injection) to reduce D/Fs on some units at a facility.

Additionally, carbon monoxide should be included in the emissions averaging provision, since some units may be able to easily meet the proposed CO limits, while, for others, it may impossible. To facilitate its inclusion, the emission limitation for CO should be expressed in an alternative form – lb/MMBtu. For the case of units using CEMS to measure CO, we reference an existing emission averaging provision for NOx found at 40 CFR 76.11. Heat input should be allowed to be determined using either flow monitors (some units subject to the NOx budget trading program have these already) or using fuel factors and diluent monitors per 40 CFR 60 Method 19.

Response: See response to comment EPA-HQ-OAR-2002-0058-2801.1, excerpt 36 for discussion of pollutants eligible for emissions averaging.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-2702.1
Comment Excerpt Number: 207

Comment: C. The 10% discount factor unless extra flexibility is provided.
EPA imposes a restriction on emissions averaging that requires facilities using that option to meet a standard that is 10% stricter than the otherwise applicable limits. 75 FR 32035. EPA should remove this 10% penalty for using emissions averaging because it is arbitrary, unnecessary for environmental protection and reduces the flexibility that averaging provides. EPA asserts that its inclusion further ensures the allowable emissions are at least as stringent as the MACT floor limits without using averaging. However, EPA offers no demonstration of this in the proposal. Given the accuracy of heat input weighted emission calculations, there is no uncertainty that the average emission rates will be any less stringent than when not using averaging. Because EPA has already determined that the standards in the rule achieve the maximum emission reduction achievable for health and environmental protection, to require an additional 10% reduction of emissions has no basis in the environmental underpinnings of the rule. Because emissions averaging is a compliance alternative, the 10% discount factor constitutes a beyond-the-floor requirement that EPA has not analyzed for its cost, non air quality and energy impacts, as required by CAA §112(d)(2). Finally, although the 10% discount may be perceived as a fair trade-off for the flexibility of emissions averaging, it still lacks a legal basis and creates a disincentive for sources to use this compliance method. Because the proposed limits in this rule are so tight, sources will not be able to ensure an additional 10% reduction in emissions below the limits and imposing this requirement effectively deprives many sources of the availability of the emissions averaging compliance alternative.

Response: See response to EPA-HQ-OAR-2002-0058-2808.1, excerpt 30 for the discount factor.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-2702.1
Comment Excerpt Number: 210

Comment: Method for Demonstrating Initial Compliance Should be Amended.
Compliance should be based solely on actual emissions: The proposed provisions require (1) a demonstration that the average weighted emissions is less than 90 percent of the applicable emissions limit assuming each unit is operating at its maximum rated heat input capacity (see Equation 1) and (2) a demonstration each calendar month that the average weighted emissions is less than the applicable emissions limit using the actual heat inputs for that month.

There is no rationale for the first test and it should be eliminated. Other rules that allow emission averaging (again, see the HON), include no such requirement. Such a requirement could be unduly restrictive. For example, a facility may have one older unit and a newer unit which they would like to average. The older unit may have a much lower capacity factor (ratio of actual usage divided by rated capacity) than the newer one. Older units typically have much more space constraints and a facility may be facing steep compliance costs to bring the older unit into compliance and may have an opportunity to over-control the newer unit. Given that the newer unit has a longer remaining life expectancy, such a facility should be incented to over control the newer unit. Yet, Equation 1 may block the facility from taking advantage of the emission averaging flexibility, especially if the older unit has a comparable or even higher rated capacity than the newer unit.

Response: See response to comment EPA-HQ-OAR-2002-0058-3137.1, excerpt 5 for actual vs. design heat input in Equation 1.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 227

Comment: Proposed 63.7522(a) allows for emission averaging within a subcategory for Cl-, PM, and Hg, if your averaged emissions are within 90 percent of the applicable emission limit. We see no justification for the 90% criteria. It certainly represents a beyond-the-floor change to the emission limits that has not been justified. Sources should not be penalized because they want to be efficient in how they reduce emissions. In those cases where a source can be more efficient by over-controlling some sources and not having to control or under-controlling other sources, they should have the right to do so and not be penalized. It will then be their responsibility to assure the average meets the emission limit and to demonstrate compliance and they should bear the risk associated with that choice.

Recommendation: The 10% discount for emission averages should be eliminated.

Response: See response to EPA-HQ-OAR-2002-0058-2808.1, excerpt 30 for the discount factor.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 228

Comment: Proposed 63.7522(c) contains an antibacksliding provisions that specifies For each existing boiler or process heater in the averaging group, 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 [THE DATE 30 DAYS AFTER PUBLICATION OF THE FINAL RULE IN THE FEDERAL REGISTER] 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 [THE DATE 30 DAYS AFTER PUBLICATION OF THE FINAL RULE IN THE FEDERAL REGISTER]. However, there is no way to demonstrate compliance because the emission rate on the 30th day after publication of the final rule is not known.

Furthermore, the entire idea is flawed since a source not in an emission average is under no such limit. The emissions from sources not in an emission average may vary anywhere below the emission limit. There is no justification for limiting sources in an emission average differently than sources outside an emission average. If a group of sources can meet the applicable emission limit most efficiently by allowing one of the sources to emit more than it has previously and over-controlling another source, there is no legal or logical justification for not allowing them to do so. Furthermore, the general duty requirement in proposed 63.7505(b) makes clear that source only must reduce emissions to the level of the standard. It rightly does not say sources in an emission average must reduce emissions below the level of the emission limit.
Recommendation: Proposed 63.7522(c) is unenforceable and unreasonable and should be deleted.

Response: 63.7522(c) to state that either the emissions being achieved or the control technology being employed must not be less stringent that the date 60 days after publication of the final rule in the federal register. If sources do not know the emission rate on the 60th day after publication they can document the control technology being employed. For example, if a source has a fabric filter installed on a unit, it cannot remove the fabric filter from the unit and then factor an uncontrolled unit into the emissions averaging calculations. This provision is intended to prevent backsliding of emissions that are currently being achieved before the effective date of the rule.

Commenter Name: Holly R. Hart
Commenter Affiliation: United Steelworkers Union
Document Control Number: EPA-HQ-OAR-2002-0058-2964.1
Comment Excerpt Number: 3

Comment: Emissions averaging is a means to ensure no one facility with multiple boilers is unfairly impacted when its overall emissions are in line with the proposed requirements. The proposed rule includes the prospect of emissions averaging for metals (PM) and acid gases (HCl). It would be appropriate to utilize the same reasoning to extend emissions averaging to organic hazardous air pollutants (organic HAP – for which CO is the proxy and dioxin/furan.

Response: See response to comment EPA-HQ-OAR-2002-0058-2801.1, excerpt 36 for discussion of pollutants eligible for emissions averaging.

Commenter Name: J. Michael Geers
Commenter Affiliation: Duke Energy
Document Control Number: EPA-HQ-OAR-2002-0058-2765.1
Comment Excerpt Number: 7

Comment: Duke Energy urges EPA to not institute a discount factor in the final rule as part of the emission averaging alternative compliance provisions
In Section III (L) (32035) EPA solicits comment on its proposed emission averaging proposal. Specifically EPA requested comments on the appropriateness of using a discount factor and whether ten percent is an appropriate value for a discount factor. Duke Energy opposes the use of a discount factor and urges EPA to not include one in the final rule. As a first point, EPA's averaging formula is constructed so that even without a discount factor, the average emissions by a group of units will be no more than what is permitted on an individual basis. Second, Duke Energy is concerned that EPA's proposed IB MACT standards are so low that there are real questions about whether sources can even comply with them while using state-of-the-art control equipment. The net effect is that rather than having a real chance at continued operation, many sources will have no reasonable alternative but to shut down. Third, even if a source can attain the standard, facilities have to operate their units at a level somewhat below a standard so as to ensure an adequate compliance margin. Sources maintain this margin so as to avoid the repercussions of violating an applicable permit limit. A reasonable averaging program can help a group of sources maintain a standard and improves overall compliance. Under EPA's proposal, however, units that normally would be in full compliance with the standard would be in violation just because they attempted to use the averaging program. As an example, a group of units that are all nine percent below the emission standards would be deemed to be in full compliance as individual units. But if a company had elected to place the same units in an averaging program, they would all be judged out of compliance because of the ten percent discount factor. Finally, the choice of 10% appears purely arbitrary and without a specific justification. Another onerous provisions in EPA's proposed averaging program include the required detailed averaging plan a facility would need to prepare and the cap on unit emissions

would not allow any unit participating in the averaging plan to have emission any higher than it had on the effective date of the proposed rule. These too appear to be arbitrary requirements. If EPA is serious about providing operational flexibility to facilities, then it must make substantial revisions to its proposed averaging provisions, including the elimination of the 10% discount factor and unit-level emission caps at historical levels.

Response: See response to EPA-HQ-OAR-2002-0058-2808.1, excerpt 30 for the discount factor.

Commenter Name: Winslow Sargeant
Commenter Affiliation: US Small Business Administration
Document Control Number: EPA-HQ-OAR-2002-0058-2916.1
Comment Excerpt Number: 9

Comment: EPA Should Provide More Flexibility for Emissions Averaging

EPA should have proposed an emissions averaging program more in line with what SERs requested rather than the restricted program outlined in the proposal. Emissions averaging is an option for individual facilities that have multiple affected sources on site that saves money and obtains the identical or better emission reductions. By allowing these facilities to average emissions across various affected units, they can focus their investments on the units that will provide the biggest environmental impact per dollar spent, rather than targeting every affected unit to meet a single limit. This approach has the potential to produce a greater emissions reduction than requiring each individual source to meet the standard, while reducing the cost of compliance to the facility, and has been successfully utilized in several proceeding rulemakings. In the proposed rule, EPA limits the flexibility and potential effectiveness of emissions averaging by placing overly strict limitations on a facility's ability to employ averaging.

First, EPA should base the emissions averaging option on actual operating times and emissions rather than on design capacity of affected units. This would have provided more flexibility for facilities that have backup units or other limited use boilers, especially since EPA chose not to create a limited use subcategory. Second, EPA should not have limited the option to encompass only those sources which fall into the same subcategory based on fuel type. This requirement is unnecessarily restrictive and severely limits the flexibility of emissions averaging. Finally, the 10 percent penalty for choosing emissions averaging is again unnecessarily restrictive and again severely limits the flexibility of emissions averaging. Furthermore, EPA waives the penalty for facilities that average across units emitting from the same stack within a facility, despite the fact that the total emissions from units emitting from the same stack are identical to emissions from units emitting from separate stacks as long as all else is held constant.

Advocacy urges EPA to reconsider the emissions averaging option and to remove the impediments to small entities using it as a viable flexibility option that are outlined above, and similar to previous rules adopted by the Agency. EPA should return to the more basic emissions averaging concept that was discussed during the panel and which the panel report unanimously recommended as an important flexibility option.

Response: See response to comment EPA-HQ-OAR-2002-0058-3213.1, excerpt 175 for emission averaging between subcategories. See response to comment EPA-HQ-OAR-2002-0058-3137.1, excerpt 5 for actual vs. design heat input in Equation 1. See response to comment EPA-HQ-OAR-2002-0058-2808.1, excerpt 30 for discussion of discount factor.

Commenter Name: Quinlan J. Shea
Commenter Affiliation: Edison Electric Institute
Document Control Number: EPA-HQ-OAR-2002-0058-2755.1
Comment Excerpt Number: 11

Comment: The facility averaging provisions should be modified.

The proposed IB MACT allows emission averaging in certain circumstances. However, the emission averaging provisions of the proposed IB MACT are so restrictive and conditional that they are unlikely to be used. The proposed rule would apply a 10% “discount factor” on any source seeking to average emissions. This discount factor makes no sense and will deter averaging. As noted previously, EPA’s proposed IB MACT standards are so low that there are significant concerns about whether sources can even comply with them using state-of-the-art control equipment. Effectively lowering those standards by 10% for sources that average emissions makes an impossible situation even more impossible. In addition, there is no legitimate reason for imposing a 10% penalty on sources that seek to average emissions. Total emissions from a single facility have the same health effects 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 10% penalty on operational flexibility has no public health benefit.

Response: See response to EPA-HQ-OAR-2002-0058-2808.1, excerpt 30 for the discount factor.

Commenter Name: Chris M. Hobson
Commenter Affiliation: Southern Company
Document Control Number: EPA-HQ-OAR-2002-0058-2741.1
Comment Excerpt Number: 12

Comment: EPA has proposed to allow emission averaging of HCl, PM, or mercury among existing sources within a plant site under certain conditions. Southern Company agrees with EPA that “averaging represents an equivalent, more flexible, and less costly alternative to controlling certain emission points to MACT levels.” However, we disagree with EPA that the actual averaging provisions represent equivalent or more flexible requirements and believe that the onerous compliance requirements will discourage sources from using averaging.

First, the proposed IB MACT requires that applicable sources with separate stacks must take a 10% “discount factor” in order to participate in averaging. As noted in Section IV of our comments, we are already concerned about our ability to achieve the limits even through the application of the maximum achievable control technology. If the best units have trouble meeting the emission limits, then it will be nearly impossible to over control enough to meet the limits under averaging AND take a 10% discount. Not only do the averaging provisions not provide flexibility to sources trying to comply, but they do not represent “equivalent” limits since they are effectively lowered by 10%. If EPA is serious about providing plant flexibility, then it must reconsider the averaging provisions. It is also noted that the proposed mercury MACT for EGUs, published in the Federal Register on January 30, 2004, did allow averaging of sources “from multiple affected units located at a common, contiguous facility site.” This rule did not require an over compliance of 10% to be able to use facility-wide averaging. Southern Company requests that EPA allow facility-wide averaging consistent with the proposed rule noted above, with no penalty for averaging.

Second, EPA has not explained why averaging is not allowed for the organic HAP, CO and dioxins/furans. Certainly the organic HAP could also benefit from the "equivalent, more flexible, and less costly alternative" of emission averaging. EPA should not only eliminate the discount factor for emission averaging, but should also allow averaging of all applicable emissions.

Response: See response to EPA-HQ-OAR-2002-0058-2808.1, excerpt 30 for the discount factor.

Commenter Name: Quinlan J. Shea
Commenter Affiliation: Edison Electric Institute
Document Control Number: EPA-HQ-OAR-2002-0058-2755.1
Comment Excerpt Number: 12

Comment: Other provisions in EPA's proposed averaging program are equally onerous: the detailed averaging plan a facility would need to prepare, and the cap on unit emissions which would not allow any unit participating in the averaging program to have emissions any higher than it had on the effective date of the proposed rule.

Response: See response to EPA-HQ-OAR-2002-0058-2824.1, excerpt 23 for response to comment on timing of first compliance demonstration. EPA has retained the averaging plan in the final rule. As this provides a compliance alternative, EPA enforcement and delegated authorities need the documentation that this alternative is being implemented according to the specified plan.

Commenter Name: Pamela F. Faggert
Commenter Affiliation: Dominion
Document Control Number: EPA-HQ-OAR-2002-0058-2908.1
Comment Excerpt Number: 27

Comment: Given the stringency of the proposed standards, EPA should eliminate the proposed ten percent discount factor and emission caps from the emissions averaging provisions.

Response: See response to EPA-HQ-OAR-2002-0058-2808.1, excerpt 30 for the discount factor.

Commenter Name: Douglas A. McWilliams
Commenter Affiliation: American Municipal Power
Document Control Number: EPA-HQ-OAR-2002-0058-2808.1
Comment Excerpt Number: 30

Comment: AMP supports EPA's use of emissions averaging as a flexible compliance alternative for facilities with multiple units. The Proposed Rule was correct to recognize emissions averaging as an "equivalent, more flexible, and less costly alternative to controlling certain emission points to MACT levels." Id. at 32034. That cost savings and additional flexibility comes at no environmental or health risk since overall emissions will fully comply with the promulgated MACT standards. However, AMP does not support the proposal to apply a "discount factor of ten percent" when emissions averaging is used to "further ensure that averaging will be at least as stringent as the MACT floor limits in the absence of averaging." 75 Fed. Reg. at 32035. This penalty erodes the very compliance flexibility that emissions averaging is designed to create without explaining why any penalty is necessary to uphold the stringency of the MACT floor.

The emissions averaging provisions in the 2004 Boiler MACT rule were substantially similar to those in the current Proposed Rule. Both allowed sources to demonstrate compliance with certain emissions limits by averaging the emissions from one or more existing sources at the same facility that are in the same subcategory. Compare 75 Fed. Reg. at 32053, with 69 Fed. Reg. at 55257. Both required sources utilizing emissions averaging to take the following steps to ensure that implementation for these units would be no less stringent than unit-by-unit implementation: (1) demonstrate that the emission rate achieved during the compliance test does not exceed the emission rate that was being achieved at a set time after publication of the final rule, (2) demonstrate that the control equipment used during the compliance test is no less effective than it was at the same set time, and (3) develop and submit an emissions averaging

implementation plan for approval. Compare 75 Fed. Reg. at 32053, with 69 Fed. Reg. at 5525859.

EPA defended its inclusion of the emissions averaging compliance alternative in the 2004 Boiler MACT rule as follows:

EPA has concluded that it is permissible to establish within a NESHAP a unified compliance regimen that permits averaging across affected units subject to the standard under certain conditions. Averaging across affected units is permitted only if it can be demonstrated that the total quantity of any particular HAP that may be emitted by that portion of a contiguous major source that is subject to the NESHAP will not be greater under the averaging mechanism than it would be if each individual affected unit complied separately with the applicable standard. Under this rigorous test, the practical outcome of averaging is equivalent in every respect to compliance by the discrete units, and the statutory policy embodied in the MACT floor provisions is, therefore, fully effectuated. [Footnote: Memorandum from Jim Eddinger, ESD Combustion Group, to Robert Wayland, ESD Combustion Group, re: Response to Public Comments on Proposed Industrial, Commercial, and Institutional Boilers and Process Heaters NESHAP (Feb. 25, 2004) (EPA-HQ-OAR-2002-0058-0611).]

The 2004 Boiler MACT rule did not contain any penalty provisions for emissions averaging, concluding that the safeguards enumerated above were sufficient. EPA has offered no explanation for why these steps are insufficient in 2010 or why a penalty of 10% is necessary to uphold the MACT floor for all sources. Nor did the intervening D.C. Circuit court decision offer any input on this topic. EPA is required to provide a "reasoned explanation . . . for disregarding facts and circumstances that underlay . . . prior policy." FCC, 129 S. Ct. at 1810. EPA’s decision to include a penalty provision in the Proposed Rule, given its prior defense of emissions averaging absent such a provision, is arbitrary and capricious.

Response: EPA determined that the discount factor is necessary in order to ensure that the emissions under an emissions averaging provision will be at least as stringent as the rule without averaging. The legal basis and rational for the HON emissions averaging provisions and the discount factor were provided in the preamble to the final HON (59 FR 19425, April 22, 1994).

Commenter Name: Chris M. Hobson
Commenter Affiliation: Southern Company
Document Control Number: EPA-HQ-OAR-2002-0058-2741.1
Comment Excerpt Number: 64

Comment: The proposed rule requires that a source establish emissions limits for each unit participating in the emissions averaging plan based on the emissions levels achieved during the initial compliance test. These proposed unit-specific "emissions caps" impose additional and unnecessary stringency in the ongoing compliance procedures. In addition, they do not allow the source to benefit from added operating flexibility if additional emissions controls are added to lower emitting units. RMB notes that the source will continue to maintain average emissions below the emissions standard during each subsequent compliance test regardless of the caps or risk eliminating one or more units from the averaging group.

The proposed rule also applies a ten percent "discount" factor to the average calculated emissions in assessing compliance with the emissions standards. This "discount factor" is an unnecessary penalty that effectively increases the stringency of the emissions standards and reduces the utility of the averaging provisions.

As noted in the vacated IB-MACT Rule, emissions averaging was included to provide greater compliance flexibility particularly for smaller, municipal electric utilities. The proposed use of emissions caps and penalty factors reduce the overall benefit of the emissions averaging and reduce the flexibility in demonstrating compliance for these sources. Given the stringency of the proposed standards, RMB recommends that EPA consider eliminating these requirements from the emissions averaging provisions.

Response: See response to EPA-HQ-OAR-2002-0058-2808.1, excerpt 30 for the discount factor. See response to comment EPA-HQ-OAR-2002-0058-2960.1, excerpt 228 for clarification of the anti-backsliding procedures.

Commenter Name: Carroll L. Missimer
Commenter Affiliation: P.H. Glatfelter Company
Document Control Number: EPA-HQ-OAR-2002-0058-2694.1
Comment Excerpt Number: 2

Comment: We agree that incorporating emissions averaging into the Boiler MACT is a proper way to encourage flexibility and cost savings for affected facilities. There is ample precedent in the MACT program for allowing emissions averaging. For example, the Pulp and Paper Chemical Recovery Combustion MACT allows plants to set a PM HAP emissions limit for each existing applicable process unit such that, if these limits are met, the total emissions from all existing process units are less than or equal to a "bubble" limit on all affected units. See 66 Fed. Reg. 3180, 3184 (January 13, 2001) and 40 C.F.R. Part 63, Subpart MM. See also 67 Fed. Reg. 78046 (December 20, 2002) (proposing emissions averaging in the Lime Manufacturing MACT). Many other MACT standards have included emissions averaging provisions, which are conceptually similar. See, e.g., 40 C.F.R. Part 63, Subpart JJJ (Group IV Polymers and Resins); 40 C.F.R. Part 63, Subpart U (Group I Polymers and Resins); 40 C.F.R. Part 63, Subpart G (Synthetic Organic Chemical Manufacturing Industry: Process Vents, Storage Vessels, Transfer Operations and Wastewater); 40 C.F.R. Part 63, Subpart LL (Primary Aluminum Reduction Plants); 40 C.F.R. Part 63, Subpart CC (Petroleum Refineries); 40 C.F.R. Part 63, Subpart EEE (Hazardous Waste Combustors).

Emissions averaging is a well demonstrated technique for meeting or exceeding environmental objectives at lower cost and with greater flexibility tailored to individual affected facilities. Provisions such as these allow plants to optimize their investments by installing controls on units where the lowest emission rates can be achieved in the most cost-effective manner possible. For example, a source could decide to over-control a newer unit in order to avoid costly investments in an older unit that may be retired before the useful life of the control device is reached. Emissions averaging provisions also provide environmental benefit by allowing for control options that minimize energy use. Energy efficient decisions benefit the environment by reducing power demands and the secondary pollutant impacts they generate.

WC concurs with EPA’s proposal and past precedent that use of the emissions averaging compliance alternative would be limited to existing units. New and reconstructed boilers/process heaters would be required to meet the more stringent "new source" requirements.

Response: See response to comment EPA-HQ-OAR-2002-0058-3213.1, excerpt 35.

Commenter Name: Stephen V. Capone
Commenter Affiliation: SABIC Innovative Plastics US LLC
Document Control Number: EPA-HQ-OAR-2002-0058-2861.1
Comment Excerpt Number: 3

Comment: One of SABIC’s major sources operates four coal-fired boilers. Two are stoker design coal-fired boilers emitting through one common stack. The other two are pulverized coal-fired units emitting through another, different common stack.

The proposed 63.7522 emission averaging provisions do not allow averaging of emissions from all existing boilers that are in different subcategories venting to separate stacks. Paragraph 63.7522(b) provides emission averaging for a group of two or more existing boilers in the same subcategory that each vent to a separate stack. Paragraphs 63.7522(h) and (j) provide emissions averaging for units in different subcategories venting through a common stack. However,

although the emission limits for particulate matter, HC1, and mercury for the pulverized coal and stoker coal subcategories are the same, there is no provision for emission averaging among pulverized coal units emitting through a common stack with emissions from stoker coal units emitting through another common stack. This would prohibit SABIC from averaging the emissions from its two groups of boilers, one of which is a pair of stoker coal units and the other of which is a pair of pulverized coal units.
We do not understand why the rule should prohibit emission averaging for a group of two or more existing coal-fired boilers in different subcategories when all coal-fired boilers must meet the same particulate matter, HCI, and mercury emission limits, regardless of stack configuration. The final rule should allow averaging such emissions to demonstrate compliance with the common emission limits.

Response: See response to comment EPA-HQ-OAR-2002-0058-3213.1, excerpt 175 for emission averaging between subcatgories. See response to comment EPA-HQ-OAR-2002-0058-2801.1, excerpt 36 for discussion of pollutants eligible for emissions averaging.

Commenter Name: Carroll L. Missimer
Commenter Affiliation: P.H. Glatfelter Company
Document Control Number: EPA-HQ-OAR-2002-0058-2694.1
Comment Excerpt Number: 3

Comment: We believe that additional flexibility should be incorporated into the proposed emissions averaging provisions in order to ensure facilities have options to reduce the cost of compliance. The emissions averaging provisions should be based on actual operating time and emissions and not capacity. Adding the element of time ensures equivalent control regardless of boiler operating schedules and provides flexibility with respect to the control strategy for limited use boilers. Some boilers are only used during maintenance outages, and incorporating flexibility into the emissions averaging provisions to accommodate limited use boilers will greatly reduce the compliance cost for these boilers. Boilers sharing common stacks should also be eligible for inclusion in the emissions averaging approach, especially if emissions can be measured from each boiler prior to the common stack. EPA has included all common stack units in its MACT floor analyses by applying the measured common emission rate to each unit, instead of one time for the group of units, so this approach could also be used in an emissions averaging compliance scenario.

Response: In the final rule limited use boilers are not subject to numeric emission limits. Therefore, we determined that additional flexibility of modifying the heat input parameter in equation 1 is not necessary.

Boilers venting to a common stack are eligible for emissions averaging as long as they are in the same subcategory. See 63.7522(k)

Commenter Name: Carroll L. Missimer
Commenter Affiliation: P.H. Glatfelter Company
Document Control Number: EPA-HQ-OAR-2002-0058-2694.1
Comment Excerpt Number: 4

Comment: Glatfelter believes that boilers of any design firing any fuel (e.g., in any subcategory) should be included in the emissions averaging provisions and that facilities should not be limited to use of emissions averaging only for boilers in the same subcategory. There is no justification for restricting emissions averaging only to boilers in a specific subcategory; facilities should be able to average emissions from stoker boilers with emissions from pulverized coal boilers and liquid boilers. This approach has been used in several of the other rules mentioned above. For example, the Pulp and Paper Chemical Recovery Combustion MACT and the HON allow emissions averaging across different types of units. The equivalency by permit provisions under 40 CFR 63.94 allow sources to "trade" emissions from unregulated sources for emissions of regulated sources, so this is additional reason not to restrict use of emissions averaging to boilers within the same subcategory.

Response: See response to comment EPA-HQ-OAR-2002-0058-3213.1, excerpt 175 for response on averaging across different subcategories.

Commenter Name: Stephen V. Capone
Commenter Affiliation: SABIC Innovative Plastics US LLC
Document Control Number: EPA-HQ-OAR-2002-0058-2861.1
Comment Excerpt Number: 4

Comment: Averaging emissions from different subcategories would be consistent with emissions averaging provided in other MACT standards. For example, pursuant to 40 CFR 63.112(t), the Hazardous Organic NESHAP (HON) allows controlling some of the emission points (e.g., individual process vents, storage vessels, transfer racks, wastewater streams) within the source to different levels than specified in 63.113 through 63.148 by using an emissions averaging compliance approach, as long as the overall emissions from the source do not exceed the emission level specified in § 63.112(a). Similarly, the NESHAP for Miscellaneous Organic Chemical Manufacturing (MON) allows emissions averaging among different emission points pursuant to 40 CFR 63.2500. Paragraph 63.2500(b) additionally provides that the batch process vents are collectively considered one individual emission point for the purposes of emissions averaging.

In addition, 63.7522 of the vacated Subpart DDDDD MACT previously provided SABIC the option to use emission averaging of the emissions from each of the two common stacks serving its four large solid fuel-fired boilers to demonstrate compliance with the common particulate, HC1, or mercury limits applicable to the four boilers.

Response: See response to comment EPA-HQ-OAR-2002-0058-3213.1, excerpt 175 for response on averaging across different subcategories.
See response to comment EPA-HQ-OAR-2002-0058-2694.1, excerpt 3, for response of how units with common stacks can participate in the emissions averaging provision.

Commenter Name: Stephen V. Capone
Commenter Affiliation: SABIC Innovative Plastics US LLC
Document Control Number: EPA-HQ-OAR-2002-0058-2861.1
Comment Excerpt Number: 5

Comment: We request that § 63.7522 provide for demonstrating compliance by averaging emissions from a common stack through which one or more pulverized coal boilers emit with emissions from a common stack through which one or more stoker coal boilers emit. One way to provide this would be to amend proposed § 63.7522 as follows (additions underlined in bold; deletions bold strike-through):
(a)(1)As an alternative to meeting the requirements of § 63.7500 for particulate matter, HC1, or mercury on a boiler or process heater-specific basis, if you have more than one existing boiler or process heater in any subcategory located at your facility, you may demonstrate compliance by emission averaging, if your
averaged emissions are within 90 percent of the applicable emission limit, according to the procedures in this section.
(2) For the purposes of emissions averaging, you may elect to deem boilers
or process heaters in separate subcategories located at the same major source to be in the same subcategory for those pollutants for which Table 2 to this subpart has the same emission limit for the separate subcategories. In such case, the emission limit applicable to the boilers or process heaters shall be the same emission limit.
To document the election, the implementation plan requirements in 63.7522(g)(2) should be amended.
(g) ***
(1) ***
(2) You must include the information contained in paragraphs (g)(2)(i) through (vii) of this section in your implementation plan for all emission sources included in an emissions average:
(i) The identification of all existing boilers and process heaters in the averaging group, including for each either the applicable HAP emission level or the control technology installed as of [DATE 60 DAYS AFTER PUBLICATION OF THE FINAL RULE IN THE FEDERAL REGISTER], and the date on which you are requesting emission averaging to commence and, for an election pursuant to 463.7522(a)(2), the identification of any existing boilers or process heaters and the subcategory you are electing to deem them;
In addition, § 63.7522(g)(4) should be changed to clarify authority to approve an emission averaging implementation plan. A proposed change to § 63.7522(g)(4) follows:
(4) The applicable regulatory authority shall not approve an emission averaging implementation plan containing any of the following provisions:
(i) Any averaging between emissions of differing pollutants or between differing sources; or
(ii) The inclusion of any emission source other than an existing unit in the same subcategory.

For purposes of emission averaging, boilers or process heaters that are deemed to be in the same subcategory pursuant to § 63.7522(a)(2) shall not
be deemed to be a differing source or to be in a different subcategory.

Response: See response to comment EPA-HQ-OAR-2002-0058-3213.1, excerpt 175 for emission averaging between subcatgories.

Commenter Name: Carroll L. Missimer
Commenter Affiliation: P.H. Glatfelter Company
Document Control Number: EPA-HQ-OAR-2002-0058-2694.1
Comment Excerpt Number: 5

Comment: We disagree that a 10 percent penalty for use of emissions averaging is appropriate. This requirement restricts the utility of the proposed emissions averaging provisions, especially as this demonstration is proposed to be based on unit capacity and not actual unit operating data. The Pulp and Paper Chemical Recovery Combustion MACT allows averaging of emissions with no requirement to further reduce emissions to 90 percent of the allowable emission rate.

We believe that the application of the underlying principles of emissions averaging, as stated in the Proposed Rule, is sufficient to ensure full realization of the statutory requirements of meeting the MACT standards for the affected sources and that no discount factor is required. EPA fails to justify the necessity to further tighten emissions standards when emissions averaging is used. This point is further reinforced by the fact that EPA expressly excluded the provisions of emissions averaging, including the discount factor, to a situation where individual units are vented through a common stack. EPA must realize that there is no difference in actual emissions between two units emitting from separate stacks and the same units, operated in an identical fashion, emitting from a common stack: the quantity of contaminants emitted to the atmosphere will be identical in both circumstances and imposing a discount factor to the units emitting separately will surely discourage any facility from using this compliance option. EPA bases its justification for including of a discount factor on the emissions averaging provisions in the Hazardous Organic NESHAP (HON), stating that the legal basis and rational for the HON emissions averaging provisions have been provided in the preamble to the final HON.[59 FR 19425, April 22, 1994] However, EPA dismisses this discount provision in the preamble to the proposed NESHAP rule for Plywood and Composite Wood Products (PCWP MACT), stating "...(the) HON sources have many emission points, are complex and diverse, and as a result are subject to a more complex set of emissions averaging provisions. The PCWP facilities have fewer emission points within each facility. Therefore, the enforcement concerns arising due to the large number of emission points in each HON facility are minimized for PCWP facilities."[68 FR 1290, January 9, 2003] EPA concludes its argument to dismissing a discount factor for PCWP sources by stating that "...(the) HON requires a discount factor of 10 percent in credit calculations to share with the environment some portion of the cost savings due to emissions averaging and to account for uncertainty in emissions estimation. Due to differences between PCWP and HON sources (discussed below), we do not believe it is necessary for the proposed PCWP rule to include a discount factor. "[68 FR 1290, January 9, 2003]. This conclusion was maintained in the final version of the PCWP MACT Rule[69 FR 45973, July 20, 2004]. In fact, the concept of imposing a discount factor on the use of emissions averaging was never discussed neither in the initially proposed [17 68 FR 1660, January 13, 2003] nor the previous final[69 FR 55218, September 13, 2004] Boiler MACT Rule. Hence we believe that imposing a discount factor to the emissions averaging compliance alternative is unwarranted and unjustified.

Response: We acknowledge the counter-rationale provided by the PWCP rulemaking, however see response to EPA-HQ-OAR-2002-0058-2808.1, excerpt 30 for the discount factor.

Commenter Name: Carroll L. Missimer
Commenter Affiliation: P.H. Glatfelter Company
Document Control Number: EPA-HQ-OAR-2002-0058-2694.1
Comment Excerpt Number: 6

Comment: Glatfelter recommends that sources be given the flexibility to use emissions averaging provisions or include alternative emission limits for dioxin as well as for PM/TSM, HCI, and mercury. For dioxin, which is a concentration based limit and not a mass based limit, the source would calculate its recommended alternative emission limits using an approach similar to that included in the Pulp and Paper Chemical Recovery Combustion MACT for the PM limits in gr/dscf, and these emission limits would be submitted to the permitting authority for approval and inclusion in the air permit. The alternative emission limits would be set during the initial compliance test. Separate alternative emission limit calculations could be submitted for PM HAP, total metals, mercury and/or HCI at the discretion of the applicant. A site's emissions averaging plan need not include all pollutants; and for any pollutants not specifically included in the emissions averaging plan, the Rule's emissions limitations would apply as a default.

[See submittal for an equation such as the following could be used to define this averaging methodology]

Response: See response to comment EPA-HQ-OAR-2002-0058-2801.1, excerpt 36 for discussion of pollutants eligible for emissions averaging.

Commenter Name: Winslow Sargeant
Commenter Affiliation: U.S. Small Business Administration
Document Control Number: EPA-HQ-OAR-2002-0058-2916
Comment Excerpt Number: 6

Comment: EPA Should Provide More Flexibility for Emissions Averaging

EPA should have proposed an emissions averaging program more in line with what SERs requested rather than the restricted program outlined in the proposal. Emissions averaging is an option for individual facilities that have multiple affected sources on site that saves money and obtains the identical or better emission reductions. By allowing these facilities to average emissions across various affected units, they can focus their investments on the units that will provide the biggest environmental impact per dollar spent, rather than targeting every affected unit to meet a single limit. This approach has the potential to produce a greater emissions reduction than requiring each individual source to meet the standard, while reducing the cost of compliance to the facility, and has been successfully utilized in several proceeding rulemakings. In the proposed rule, EPA limits the flexibility and potential effectiveness of emissions averaging by placing overly strict limitations on a facility’s ability to employ averaging.

First, EPA should base the emissions averaging option on actual operating times and emissions rather than on design capacity of affected units. This would have provided more flexibility for facilities that have backup units or other limited use boilers, especially since EPA chose not to create a limited use subcategory. Second, EPA should not have limited the option to encompass only those sources which fall into the same subcategory based on fuel type. This requirement is unnecessarily restrictive and severely limits the flexibility of emissions averaging. Finally, the 10 percent penalty for choosing emissions averaging is again unnecessarily restrictive and again severely limits the flexibility of emissions averaging. Furthermore, EPA waives the penalty for facilities that average across units emitting from the same stack within a facility, despite the fact that the total emissions from units emitting from the same stack are identical to emissions from units emitting from separate stacks as long as all else is held constant.

Advocacy urges EPA to reconsider the emissions averaging option and to remove the impediments to small entities using it as a viable flexibility option that are outlined above, and similar to previous rules adopted by the Agency. EPA should return to the more basic emissions averaging concept that was discussed during the panel and which the panel report unanimously recommended as an important flexibility option.

Response: See response to comment EPA-HQ-OAR-2002-0058-3213.1, excerpt 175 for emission averaging between subcatgories. See response to comment EPA-HQ-OAR-2002-0058-3137.1, excerpt 5 for actual vs. design heat input in Equation 1.
See response to comment EPA-HQ-OAR-2002-0058-2808.1, excerpt 30 for discussion of discount factor.

Commenter Name: Ann W. McIver
Commenter Affiliation: Citizens Energy Group
Document Control Number: EPA-HQ-OAR-2002-0058-2875.1
Comment Excerpt Number: 6

Comment: As proposed, the use of emissions averaging is limited to units in the same designated subcategories. Citizens would like to encourage EPA to allow averaging across subcategories (of the same fuel) in order to allow facilities to make cost-effective investments in technologies and other strategies designed to achieve the reductions required under this regulation. In many cases, especially with the facilities that are likely subject to the proposed rules, the geographical location of the physical plant may be located in a congested area of the site that will not readily accommodate installation of control technologies. However, these same facilities may have the ability to "over-comply" on one or more emission units in order to ensure the environmental benefits are realized.

Recognizing that not all subcategories have identical emission limits under this proposed rule, Citizens believes that the provisions of 40 CFR 76.11, Emissions Averaging provisions under the Acid Rain Nitrogen Oxides Emissions Reduction Program, provides a model that sources may be able to use to ensure the environmental benefits are achieved.

Response: See response to comment EPA-HQ-OAR-2002-0058-3213.1, excerpt 175 for emission averaging between subcategories.

Commenter Name: Carroll L. Missimer
Commenter Affiliation: P.H. Glatfelter Company
Document Control Number: EPA-HQ-OAR-2002-0058-2694.1
Comment Excerpt Number: 7

Comment: The proposed rule contains a requirement for the facility to demonstrate each month that the average weighted emissions of the boilers included in the emissions averaging scheme are below the applicable emission limit using the actual heat inputs for that month. Glatfelter believes that an annual determination that the emission limits under the emissions averaging approach are being met is more than satisfactory to ensure protection of public health and welfare and appropriate for consideration for a technology-based MACT standard. The first compliance demonstration should not be required immediately after the rule compliance date, as maintenance and outage schedules may make it hard for a facility to comply with the emissions averaging provisions without 12 full months of data. Other rules do not require a monthly test (e.g., the HON), but provide a 30 percent allowance during each quarter and equivalency on an annual basis. Although a year is an appropriate period for determining the time-weighted average emissions rate, consideration may be given for convenience sake to a shorter 6 month period that coincides with the required reporting period for the standard. It is expected that a 6 to 12 month period would provide the flexibility needed to retain the benefit of the recommended averaging provisions.

Response: See response to EPA-HQ-OAR-2002-0058-3213.1, excerpt 180 for response to comment on monthly compliance determinations.

Commenter Name: Bill Perdue
Commenter Affiliation: American Home Furnishings Alliance
Document Control Number: EPA-HQ-OAR-2002-0058-2692.1
Comment Excerpt Number: 10

Comment: We disagree with EPA's assertion that a 10% "discount factor" for emissions averaging "will further ensure that averaging will be at least as stringent as MACT floor limits in the absence of averaging." Averaged MACT sources that meet the MACT limitation are, by definition, as stringent as the MACT limitation in question; if the EPA does not believe that any source should ever exceed the emission limitation regardless of ability to average, then averaging would not be a viable proposal. We must conclude that the EPA is proposing a beyond the floor analysis, in which case an economic analysis is required.

Response: See response to EPA-HQ-OAR-2002-0058-2808.1, excerpt 30 for the discount factor.

Commenter Name: Jerry Osheka
Commenter Affiliation: PPG Industries
Document Control Number: EPA-HQ-OAR-2002-0058-2938.1
Comment Excerpt Number: 12

Comment: We agree that incorporating emissions averaging into the Boiler MACT is a proper way to encourage flexibility and cost savings for affected facilities.

Response: EPA acknowledges support of the emission averaging provision and has retained the emission averaging provision in the final rule.

Commenter Name: Jerry Osheka
Commenter Affiliation: PPG Industries
Document Control Number: EPA-HQ-OAR-2002-0058-2938.1
Comment Excerpt Number: 13

Comment: A 10% Discount Factor is Unreasonable to Apply When the Emissions Averaging Option is Used.
We believe that the underlying principles of emissions averaging, as stated in the Proposed Rule, is sufficient to ensure full realization of the statutory requirements of meeting the MACT standards for the affected sources and that no discount factor is required. EPA fails to justify the necessity to further tighten emissions standards when emissions averaging is used.

This point is further reinforced by the fact that EPA expressly excluded the provisions of emissions averaging, including the discount factor, to a situation where individual units are vented through a common stack. EPA must realize that there is no difference in actual emissions between two units emitting from separate stacks and the same units, operated in an identical fashion, emitting from a common stack. We agree with EPA's proposal for demonstrating compliance from units that emit through a common stack and believe that the same averaging approach should be applied to units that emit from separate stacks. Penalizing units that emit from separate stacks by imposing a discount factor for emissions averaging is unnecessarily stringent and will surely discourage any facility from using this compliance option.

Response: See response to EPA-HQ-OAR-2002-0058-2808.1, excerpt 30 for the discount factor.

Commenter Name: Lee B. Zeugin
Commenter Affiliation: Utility Air Regulatory Group
Document Control Number: EPA-HQ-OAR-2002-0058-2880.1
Comment Excerpt Number: 13

Comment: The proposed IB MACT rule allows emission averaging in certain circumstances. While emission averaging can, in theory, provide operational flexibility to sources, the emission averaging provisions of the proposed rule are so restrictive and highly conditioned that they are unlikely to be used. The proposed rule would apply a 10% "discount factor" on any source seeking to average emissions. This discount factor makes no sense and will deter averaging. As previously noted, EPA's proposed IB MACT standards are so low that there are real questions about whether sources can comply with them using state-of-the-art control equipment. Effectively lowering those standards by 10% for sources that choose to average emissions makes an impossible compliance situation even worse. Also, there is no legitimate reason for imposing a 10% penalty of sources that seek to average emissions. Total emissions from a single facility have the same health effects 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 remain the same. The proposed 10% penalty on operational flexibility yields no public heath benefits.

Response: See response to EPA-HQ-OAR-2002-0058-2808.1, excerpt 30 for the discount factor.

Commenter Name: Lee B. Zeugin
Commenter Affiliation: Utility Air Regulatory Group
Document Control Number: EPA-HQ-OAR-2002-0058-2880.1
Comment Excerpt Number: 14

Comment: Other onerous provisions in EPA's proposed averaging program include the detailed averaging plan a facility would need to prepare and the cap on unit emissions that would not allow any unit participating in the averaging to have emissions any higher that it had on the effective date of the proposed rule. If EPA is serious about providing operational flexibility to facilities through facility averaging, then it must make substantial revisions to its proposed averaging provisions.

Response: See response to EPA-HQ-OAR-2002-0058-2824.1, excerpt 23 for response to comment on timing of first compliance demonstration. See response to EPA-HQ-OAR-2002-0058-2835.1, excerpt 17 for submittal of the emission averaging plan.

Commenter Name: Jerry Osheka
Commenter Affiliation: PPG Industries
Document Control Number: EPA-HQ-OAR-2002-0058-2938.1
Comment Excerpt Number: 14

Comment: Requiring Monthly Compliance Demonstrations is Overly Burdensome and Unreasonable. The proposed rule contains a requirement for the facility to demonstrate each month that the average weighted emissions of the boilers included in the emissions averaging scheme are below the applicable emission limit using the actual heat inputs for that month. PPG believes that an annual determination that the emissions averaging limits are being met is more than satisfactory to ensure protection of public health and welfare and appropriate for consideration for a technology-based MACT standard. The first compliance demonstration should not be required immediately after the rule compliance date, as maintenance and outage schedules may make it difficult for a facility to comply with the emissions averaging provisions without 12 full months of data. Other rules do not require a monthly test (e.g., the HON), but provide a 30 percent allowance during each quarter and equivalency on an annual basis. Although a year is an appropriate period for determining the time-weighted average emissions rate, consideration may be given for convenience sake to a shorter 6 month period that coincides with the required reporting period for the standard. It is expected that a 6 to 12 month period would provide the flexibility needed to retain the benefit of the recommended averaging provisions.

Response: See response to EPA-HQ-OAR-2002-0058-3213.1, excerpt 180 for response frequency of compliance determinations for emission averaging.

Commenter Name: Jerry Osheka
Commenter Affiliation: PPG Industries
Document Control Number: EPA-HQ-OAR-2002-0058-2938.1
Comment Excerpt Number: 15

Comment: Emissions Averaging Should be Allowed for Dioxin As Well As PM, HCl, and Mercury. PPG recommends that EPA give sources the flexibility to use emissions averaging provisions for dioxin as well as for PM/TSM, HCl, and mercury. For dioxin, which is a concentration based limit and not a mass based limit, the source would calculate its recommended limits using an approach similar to that included in the Pulp and Paper Chemical Recovery Combustion MACT for the PM limits in gr/dscf, and these limits would be submitted to the permitting authority for approval and inclusion in the air permit. The alternative limits would be set during the initial compliance test.

Response: See response to comment EPA-HQ-OAR-2002-0058-2801.1, excerpt 36 for discussion of pollutants eligible for emissions averaging.

Commenter Name: Bill Wemhoff
Commenter Affiliation: National Rural Electric Cooperative Association
Document Control Number: EPA-HQ-OAR-2002-0058-2835.1
Comment Excerpt Number: 16

Comment: The proposed IB MACT rule allows emission averaging in certain circumstances. While emission averaging can, in theory, provide operational flexibility to sources, the emission averaging provisions of the proposed rule are so restrictive and highly conditioned that they are unlikely to be used. The proposed rule would apply a 10 percent "discount factor" on any source seeking to average emissions across units at a facility. This discount factor will deter averaging. As noted elsewhere in these comments, EPA's proposed IB MACT standards are so low that there are real questions about whether sources can even comply with them using state-of-the-art control equipment. By effectively lowering those standards further by 10 percent for sources that average emissions, it makes an impossible situation even more impossible. Also, there is no legitimate reason for imposing a 10 percent penalty on sources that seek to average emissions. Total emissions from a single facility have the same health effects 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. The 10 percent penalty on operational flexibility has no public heath benefit.

Response: See response to EPA-HQ-OAR-2002-0058-2808.1, excerpt 30 for the discount factor.

Commenter Name: Bill Wemhoff
Commenter Affiliation: National Rural Electric Cooperative Association
Document Control Number: EPA-HQ-OAR-2002-0058-2835.1
Comment Excerpt Number: 17

Comment: Onerous provisions in EPA's proposed averaging program include the detailed averaging plan a facility would need to prepare and the cap on unit emissions would not allow any unit participating in the averaging to have emission any higher then it had on the effective date of the proposed rule. If EPA is serious about providing operational flexibility to facilities, then it must make substantial revisions to its proposed averaging provisions.

Response: See response to EPA-HQ-OAR-2002-0058-2824.1, excerpt 23 for response to comment on timing of first compliance demonstration. EPA has retained the averaging plan in the final rule. As this provides a compliance alternative, EPA enforcement and delegated authorities need the documentation that this alternative is being implemented according to the specified plan.

Commenter Name: Edward E. Quick
Commenter Affiliation: Celanese International Corp

Document Control Number: EPA-HQ-OAR-2002-0058-2840.1
Comment Excerpt Number: 22

Comment: Because the 90 percent emissions limit is arbitrary, EPA must allow straight emissions averaging across existing sources within the same source category.

Compliance with emission limits should be based solely on actual emissions as has been the case with previous MACT rulemaking. The proposed provisions require (1) a demonstration that the average weighted emissions are less than 90 percent of the applicable emissions limit assuming each unit is operating at its maximum rated heat input capacity, and (2) a demonstration each calendar month that the average weighted emissions is less than the applicable emissions limit using the actual heat inputs for that month.

The 90% factor is baseless and should be eliminated. The existing NESHAP regulations (HON and MON, for example) provide for straight emission averaging without an arbitrary 90% factor, and EPA has provided no justification for imposing the 90% factor.

In addition, there is no justification for imposing emission standards calculated by two compliance methods for the same equipment. Averaging of emissions based on actual heat input is the technically correct methodology.

Response: See response to EPA-HQ-OAR-2002-0058-2808.1, excerpt 30 for the discount factor.

Commenter Name: Robert Thornton
Commenter Affiliation: International District Energy Association
Document Control Number: EPA-HQ-OAR-2002-0058-2918.1
Comment Excerpt Number: 23

Comment: Emissions averaging across categories should be allowed

In the proposed rule, the use of emissions averaging is limited to units in the same designated subcategories. IDEA encourages EPA to allow averaging across subcategories, thereby allowing facilities to make cost-effective investments in technologies and other strategies designed to achieve the reductions required under this regulation. In many facilities that are likely subject to the proposed rules, some plant equipment may be located in a congested area of the site in which it is difficult or impossible to install control technologies. On the other hand, other equipment at the same site may have space and the cost-effective ability to “over-comply” on one or more emission units in order to ensure the overall reductions are achieved.

Response: See response to comment EPA-HQ-OAR-2002-0058-3213.1, excerpt 175 for response on averaging across different subcategories.

Commenter Name: Brad James
Commenter Affiliation: Trinity Consultants
Document Control Number: EPA-HQ-OAR-2002-0058-2853.1
Comment Excerpt Number: 26

Comment: EPA proposes that a discount factor be applied when facilities choose to comply with the standard by averaging the emissions of their various sources. Both the presence of a discount factor and the value selected by EPA are unreasonable. When the proposed standard is already a daily or monthly average, discounting is unnecessary. Any data collection-oriented deviations the discount factor may be designed to prevent are already balanced out by the daily and monthly averages of each source. It is unclear, therefore, how a discount factor contributes to the accuracy of the facility's compliance status.

Response: See response to EPA-HQ-OAR-2002-0058-2808.1, excerpt 30 for the discount factor.

Commenter Name: Brad James
Commenter Affiliation: Trinity Consultants
Document Control Number: EPA-HQ-OAR-2002-0058-2853.1
Comment Excerpt Number: 27

Comment: The emissions averaging option is not allowed in the proposed rule for dioxins and furans emissions, which U.S. Sugar feels is not an effective use of this alternative compliance option since the option would have the most benefit for the dioxins and furans emission limits as these pollutants do not have extensive histories with control options (or test data).

Response: See response to comment EPA-HQ-OAR-2002-0058-2801.1, excerpt 36 for discussion of pollutants eligible for emissions averaging.

Commenter Name: Brad James
Commenter Affiliation: Trinity Consultants
Document Control Number: EPA-HQ-OAR-2002-0058-2853.1
Comment Excerpt Number: 28

Comment: EPA is proposing conflicting rules, as facilities whose sources emit to a common stack will not be subject to the discount factor. This proposal unjustifiably incentivizes the use of a common stack. Providing such a competitive advantage to certain facilities without good reason undermines the legitimacy of the proposal.

Response: See response to EPA-HQ-OAR-2002-0058-2808.1, excerpt 30 for the discount factor. EPA has developed several compliance flexibilities in this rule, and treatment of common stacks and the emissions averaging provision are two of such compliance flexibilities. Facilities whose sources vent to a common stack and want to use the emissions averaging provision are also subject to the discount factor. Facilities that opt to comply with the provisions set forth for common stacks without using emissions averaging are not subject to a discount factor. The requirements and language of the common stack option are a result of an earlier focused Agency reconsideration and the resulting public comments received on that reconsideration (See 71 FR 70651). The common stack introduces testing flexibility since testing emissions from a common stack for a group of boilers would be equivalent to the average emissions calculated from individual stack tests on each unit contributing to the stack emissions. Testing once per stack reduces the testing costs associated with boilers venting to the same stack. The scope of applicable sources is very narrow since not all units at a facility vent to a common stack. The emissions averaging option introduces a broader compliance flexibility, and since some units may opt to over control some sources while undercontrolling other sources in order to stategically allocate capital for control devices. EPA determined that given prior precedence for a discount factor in emissions averaging situations, and the broader impact emission averaging has on similar units across a facility, that a discount factor remains appropriate. Further, in many cases EPA notes that more than one of these compliance flexibilities is available to regulated entities.

Commenter Name: Brad James
Commenter Affiliation: Trinity Consultants
Document Control Number: EPA-HQ-OAR-2002-0058-2853.1
Comment Excerpt Number: 29

Comment: The discount value of 10% proposed by EPA is excessive. Although there is no basis for any discount factor, if EPA determines one should be imposed, a more reasonable value should be considered. EPA has provided no justification for its selection of 10% and has provided no indication of what its specific concerns are in the averaging process. Any statistical anomalies that could hypothetically result from averaging could be eliminated by a smaller discount factor. The 10% discount factor reduces an already determined slim compliance margin regarding the PM emission limit for U.S. Sugar's existing Boiler Nos. 7 and 8 based on historical compliance testing for each unit. As previously identified, Boiler No. 7 was utilized by EPA in establishing the MACT Floor so it would be assumed that the unit can meet the PM emissions limit as it would be "achieved under the worst foreseeable circumstances." Furthermore, Boiler No. 8 is the newest unit at the Clewiston facility and was designed to meet the previous version of the Boiler MACT emission limitations. Even with these two controlled boilers, the emissions averaging is not a viable option based on historical compliance testing data when combining with the other similar source units (Boiler Nos. 1, 2, and 4) PM compliance testing data.

Emissions averaging is clearly a permissible application of the emission limitations standards. See 59 Fed. Reg. 19,402, 19,425 (Apr. 22, 1994). Its use allows facilities some flexibility in choosing the means for reducing their emissions, thereby reducing some of the economic burden, while still accomplishing EPA's goal of establishing more stringent emission limits. EPA's use of a discount factor, particularly one as high as 10%, unreasonably interferes with companies' ability to find the most efficient means (from both an economic and environmental perspective) to comply with the emission limits.

Response: See response to EPA-HQ-OAR-2002-0058-2808.1, excerpt 30 for the discount factor.

Commenter Name: Bruce A. Steiner
Commenter Affiliation: American Coke and Coal Chemicals Institute
Document Control Number: EPA-HQ-OAR-2002-0058-2849.1
Comment Excerpt Number: 30

Comment: ACCCI supports EPA's use of emissions averaging as a flexible compliance alternative for facilities with multiple units. The Proposed Rule was correct to recognize emissions averaging as an "equivalent, more flexible, and less costly alternative to controlling certain emission points to MACT levels." Id. at 32034. That cost savings and additional flexibility comes at no environmental or health risk since overall emissions will fully comply with the promulgated MACT standards. However, ACCCI does not support the proposal to apply a "discount factor often percent" when emissions averaging is used to "further ensure that averaging will be at least as stringent as the MACT floor limits in the absence of averaging." 75 FR at 32035. This penalty erodes the very compliance flexibility that emissions averaging is designed to create without explaining why any penalty is necessary to uphold the stringency of the MACT floor.

The emissions averaging provisions in the 2004 Boiler MACT Rule were substantially similar to those in the current Proposed Rule. Both allowed sources to demonstrate compliance with certain emissions limits by averaging the emissions from one or more existing sources at the same facility that are in the same subcategory. Compare 75 FR at 32053, with 69 FR at 55257. Both required sources utilizing emissions averaging to take the following steps to ensure that implementation for these units would be no less stringent than unit-by-unit implementation: (1) demonstrate that the emission rate achieved during the compliance test does not exceed the emission rate that was being achieved at a set time after publication of the final rule, (2) demonstrate that the control equipment used during the compliance test is no less effective than it was at the same set time, and (3) develop and submit an emissions averaging implementation plan for approval. Compare 75 FR at 32053, with 69 FR at 55258-59.
EPA defended its inclusion of the emissions averaging compliance alternative in the 2004 Boiler MACT Rule as follows:
EPA has concluded that it is permissible to establish within a NESHAP a unified compliance regimen that permits averaging across affected units subject to the standard under certain conditions. Averaging across affected units is permitted only if it can be demonstrated that the total quantity of any particular HAP that may be emitted by that portion of a contiguous major source that is subject to the NESHAP will not be greater under the averaging mechanism than it would be if each individual affected unit complied separately with the applicable standard. Under this rigorous test, the practical outcome of averaging is equivalent in every respect to compliance by the discrete units, and the statutory policy embodied in the MACT floor provisions is, therefore, fully effectuated.
The 2004 Boiler MACT Rule did not contain any penalty provisions for emissions averaging, concluding that the safeguards enumerated above were sufficient. EPA has offered no

explanation for why these steps are insufficient in 2010, or why a penalty of 10% is necessary to uphold the MACT floor for all sources. Nor did the intervening D.C. Circuit court decision offer any input on this topic. EPA is required to provide a “reasoned explanation ... for disregarding facts and circumstances that underlay ... prior policy.” FCC v. Fox Television Stations, Inc., 129 S. Ct. at 1810. EPA’s decision to include a penalty provision in the Proposed Rule, given its prior defense of emissions averaging absent such a provision, is arbitrary and capricious. [Footnote 17: Memorandum from Jim Eddinger, ESD Combustion Group, to Robert Wayland, ESD Combustion Group, re: Response to Public Comments on Proposed Industrial, Commercial, and Institutional Boilers and Process Heaters NESHAP (Feb. 25, 2004) (EPA-HQ-OAR-2002-0058-0611).]

Response: See response to EPA-HQ-OAR-2002-0058-2808.1, excerpt 30 for the discount factor.

Commenter Name: David O'Keefe
Commenter Affiliation: USEC, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-3122
Comment Excerpt Number: 33

Comment: Emission averaging. EPA’s proposed discount factor of ten percent to be applied when emission averaging is used appears to be contrary to one of EPA’s stated reasons for proposing averaging, namely, “...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.”

The application of a 10% discount factor for emissions averaging is inappropriate as it penalizes cost-effectiveness and flexibility to achieve compliance.

Response: See response to EPA-HQ-OAR-2002-0058-2808.1, excerpt 30 for the discount factor.

Commenter Name: Sheila C. Holman
Commenter Affiliation: North Carolina Department of Environment and Natural Resources
Document Control Number: EPA-HQ-OAR-2002-0058-2798.1
Comment Excerpt Number: 34

Comment: The NC DAQ supports the use of emissions averaging without the application of a 10% discount factor. In the proposed rule, EPA indicates that the “discount factor will further ensure that averaging will be last as stringent as the MACT floor limits in the absence of averaging.” NC DAQ believes that the testing, monitoring, and recordkeeping in the proposed rule is sufficient to determine whether the emissions from a group of individual units is unnecessary to achieve the goals the MACT standard, and it discourages facilities from utilizing this compliance option that could otherwise provide improved flexibility and cost savings to American industry.

Response: See response to EPA-HQ-OAR-2002-0058-2808.1, excerpt 30 for the discount factor.

Commenter Name: Sarah E. Amick
Commenter Affiliation: Rubber Manufacturers Association
Document Control Number: EPA-HQ-OAR-2002-0058-2941.1
Comment Excerpt Number: 36

Comment: The proposed emission averaging is explained as allowing averaging only within a subcategory (75 Fed.Reg. at 32,034) although it is not clear from the proposed rule language if this is what EPA intended. See § 63.7522(a), 75 Fed.Reg. at 32,053. While the wording under the separate stack requirements does seem to have this restriction, the wording under the common stack requirements does not. See Equation 6, 75 Fed.Reg. 32,055. EPA provides no justification for restricting averaging to a given subcategory nor is it rational to impose such a restriction.
Some affected units involve multiple boilers operating in different subcategories (e.g. stokers and pulverized coal). These boilers are generally located in separate powerhouses. The goal of emissions averaging is to allow facilities to more tightly control some emissions points while applying fewer controls to others, thus achieving the required emission limitations in the most cost-effective manner possible. This could be best achieved by EPA removing the restriction (or clarifying its intent) that such averaging would be allowed for all affected units, regardless of whether the boilers emit through separate or "common stacks." The rule should allow for averaging across all solid fuel units (coal or biomass) regardless of category of pollutants to be averaged so long as emissions from a single unit can be quantified with testing either in the breeching or in the stack when other units aren't operating.
Allowing averaging across subcategories within the rule is consistent with the four averaging criteria described in the preamble:

1-No averaging between different types of pollutants,
2-No averaging between sources that are not part of the same affected source,
3-No averaging between individual sources within a single major source if the individual sources are not subject to the same NESHAP, and
4- No averaging between existing sources and new sources. 75 Fed.Reg. 32035.

Thus, averaging across subcategories is a possible interpretation of the proposal, and EPA could revise this in the final rule.

The legal precursor to introducing emissions averaging is Chevron U.S.A., Inc. v. NRDC, 467 U.S. 837 (1984). In Chevron, the Supreme Court held that EPA regulations allowing states to treat all of the pollution-emitting devices within the same industrial grouping as though they were encased within a single "bubble" were based on a reasonable construction by EPA. This case opened the door to more specific emissions averaging efforts, such as those implemented in the 1994 Hazardous Organic NESHAP, 59 Fed.Reg. 19,425 (April 22, 1994)(HON Rule). Several rules have followed the HON Rule in authorizing emissions averaging, and the D.C.

Circuit has never invalidated the approach. it does not appear that any such authorizations have succumbed to legal challenge. The proposed emissions averaging provisions in the Boiler Rule are directly based on the emissions averaging provisions in the HON.

In the HON Rule, EPA thoroughly examined the legal basis for emissions averaging, and explored the degree of averaging permitted under §112(d) of the Clean Air Act. At the end of its review, EPA concluded that the Clean Air Act "does not define source category, nor does it impose precise limits on the Administrator's discretion to define source." Id. EPA further acknowledged that the Clean Air Act does not limit how standards are to be set for a category or subcategory beyond requiring that it be applicable to all sources in a category, be written as a numerical limit wherever feasible, and be at least as stringent as the floor. Id.
In promulgating the HON emissions averaging rules, on which the Boiler Rule relies, EPA concluded that "the relevant statutory language is broad enough to permit the Administrator to allow sources to meet the MACT through the use of emissions averaging provided the standard applies to every source in the category, averaging does not cross source boundaries, and the standard is no less stringent than the floor." Id. Allowing emissions averaging across subcategories within the Boiler Rule is consistent with the parameters established in the HON rule, and reiterated in the Boiler Rule preamble. See 75 Fed.Reg. at 32,035. Namely, allowing averaging across subcategories will not result in averaging between (a) different types of pollutants, (b) sources that are not part of the same affected source, (c) individual sources within a single major source if the individual sources are not subject to the same NESHAP, and (d) existing sources and new sources. Id. at 32,034.

There is precedent in MACT standards for allowing averaging across different types of units of a single source. For example, the HON rule allows process vents, storage vessels, transfer racks, and wastewater streams to all be included in an emission average across an affected source. 40 CFR Subpart G. EPA reasoned that averaging needed to be allowed across all emission points (except equipment leaks) in order to provide as much flexibility as possible while maintaining an enforceable emission limitation. 59 Fed.Reg. 19,425. Similar mechanisms have been adopted in other MACT standards. See, e.g. Petroleum Refinery NESHAP, 60 Fed.Reg. 43244, 43254 (Aug. 18, 1995)(allowing wide range of emission sources to be averaged, noting that "EPA has the flexibility to allow trading within a facility that includes units in different source categories"); Boat Manufacturing NESHAP, 66 Fed.Reg. 44,218; 44,232 (Aug. 22, 2001).
As in the HON, the compliance methodology can easily accommodate subcategories with different emission limits for a given pollutant. This is done basically by calculating a weighted average allowable mass emission and a weighted average actual mass emission each month using heat inputs or steam production for each unit.

Response: See response to comment EPA-HQ-OAR-2002-0058-3213.1, excerpt 175 for emission averaging between subcatgories. The final rule retained the common stack provisions to allow units from different subcategories that share a common stack to comply using a separate Equation 6. See response to comment EPA-HQ-OAR-2002-0058-2702.1, excerpt 205 for discussion of the legal case Chevron U.S.A., Inc. v. NRDC.

Commenter Name: Sarah E. Amick
Commenter Affiliation: Rubber Manufacturers Association
Document Control Number: EPA-HQ-OAR-2002-0058-2941.1
Comment Excerpt Number: 38

Comment: Averaging across subcategories should be permitted for dioxins/furans and carbon monoxide. A source should be allowed to comply with the dioxin/furan (D/F) standard via emission averaging. While it may not be appropriate to set numerical emission standards for D/F, if the final rule does include such numerical standards, a source with multiple units could choose to comply by installing a post-combustion control (such as powder activated carbon injection) to reduce D/Fs on some units at a facility.

Additionally, carbon monoxide should be included in the emissions averaging provision, since some units may be able to easily meet the proposed CO limits, while, for others, it may impossible. To facilitate its inclusion, the emission limitation for CO should be expressed in an alternative form – lb/mmBtu. For the case of units using CEMS to measure CO, precedent exists for this as well, in the emission averaging provision for NOx found at 40 CFR 76.11. Heat input should be allowed to be determined using either flow monitors (some units subject to the NOx budget trading program have these already) or using fuel factors and diluent monitors per 40 CFR 60 Method 19.

Response: See response to comment EPA-HQ-OAR-2002-0058-2801.1, excerpt 36 for discussion of pollutants eligible for emissions averaging and response to EPA-HQ-OAR-2002-0058-2702.1, excerpt 206 for alternative units of measure for CO.

Commenter Name: Sarah E. Amick
Commenter Affiliation: Rubber Manufacturers Association
Document Control Number: EPA-HQ-OAR-2002-0058-2941.1
Comment Excerpt Number: 39

Comment: EPA imposes a restriction on emissions averaging that requires facilities using that option to meet a standard that is 10% stricter than the otherwise applicable limits. 75 Fed.Reg. at 32,035. EPA should remove this 10% penalty for using emissions averaging because it is arbitrary, unnecessary for environmental protection and reduces the flexibility that averaging provides. EPA asserts that its inclusion further ensures the allowable emissions are at least as stringent as the MACT floor limits without using averaging. However, EPA offers no demonstration of this in the proposal. Given the accuracy of heat input weighted emission calculations, there is no uncertainty that the average emission rates would be any less stringent than when not using averaging.

Because EPA has already determined that the standards in the rule achieve the maximum emission reduction achievable for health and environmental protection, to require an additional 10% reduction of emissions has no basis in the environmental underpinnings of the rule. Because emissions averaging is a compliance alternative, the 10% discount factor constitutes a beyond-the-floor requirement that EPA has not analyzed for its cost, non air quality and energy impacts, as required by CAA §112(d)(2). Finally, although the 10% discount may be perceived as a fair trade-off for the flexibility of emissions averaging, it still lacks a legal basis and creates a disincentive for sources to use this compliance method. Because the proposed limits in this rule are so tight, sources would not be able to ensure an additional 10% reduction in emissions below the limits and imposing this requirement effectively deprives many sources of the availability of the emissions averaging compliance alternative.

Response: See response to EPA-HQ-OAR-2002-0058-2808.1, excerpt 30 for the discount factor.

Commenter Name: Kevin M. Dempsey
Commenter Affiliation: American Iron and Steel Institute
Document Control Number: EPA-HQ-OAR-2002-0058-2998.1
Comment Excerpt Number: 45

Comment: Emissions Averaging is Appropriate but Should Not be Penalized

AISI supports EPA's use of emissions averaging as a flexible compliance alternative for facilities with multiple units. The Proposed Rule was correct to recognize emissions averaging as an "equivalent, more flexible, and less costly alternative to controlling certain emission points to MACT levels." Id. at 32034. That cost savings and additional flexibility comes at no environmental or health risk since overall emissions will fully comply with the promulgated MACT standards. However, AISI does not support the proposal to apply a "discount factor of ten percent" when emissions averaging is used to "further ensure that averaging will be at least as stringent as the MACT floor limits in the absence of averaging." 75 FR at 32035. This penalty erodes the very compliance flexibility that emissions averaging is designed to create without explaining why any penalty is necessary to uphold the stringency of the MACT floor.

The emissions averaging provisions in the 2004 Boiler MACT Rule were substantially similar to those in the current Proposed Rule. Both allowed sources to demonstrate compliance with certain emissions limits by averaging the emissions from one or more existing sources at the same facility that are in the same subcategory. Compare 75 FR at 32053, with 69 FR at 55257. Both required sources utilizing emissions averaging to take the following steps to ensure that implementation for these units would be no less stringent than unit-by-unit implementation: (1) demonstrate that the emission rate achieved during the compliance test does not exceed the emission rate that was being achieved at a set time after publication of the final rule, (2) demonstrate that the control equipment used during the compliance test is no less effective than it was at the same set time, and (3) develop and submit an emissions averaging implementation plan for approval. Compare 75 FR at 32053, with 69 FR at 55258-59.

EPA defended its inclusion of the emissions averaging compliance alternative in the 2004 Boiler MACT Rule as follows:

EPA has concluded that it is permissible to establish within a NESHAP a unified compliance regimen that permits averaging across affected units subject to the standard under certain conditions. Averaging across affected units is permitted only if it can be demonstrated that the total quantity of any particular HAP that may be emitted by that portion of a contiguous major source that is subject to the NESHAP will not be greater under the averaging mechanism than it would be if each individual affected unit complied separately with the applicable standard. Under this rigorous test, the practical outcome of averaging is equivalent in every respect to compliance by the discrete units, and the statutory policy embodied in the MACT floor provisions is, therefore, fully effectuated.[Memorandum from Jim Eddinger, ESD Combustion Group, to Robert Wayland, ESD Combustion Group, re: Response to Public Comments on Proposed Industrial, Commercial, and Institutional Boilers and Process Heaters NESHAP (Feb. 25, 2004) (EPA-HQ-OAR-2002-0058-0611).]

The 2004 Boiler MACT Rule did not contain any penalty provisions for emissions averaging, concluding that the safeguards enumerated above were sufficient. EPA has offered no explanation for why these steps are insufficient in 2010, or why a penalty of 10% is necessary to uphold the MACT floor for all sources. Nor did the intervening D.C. Circuit court decision offer any input on this topic. EPA is required to provide a “reasoned explanation ... for disregarding facts and circumstances that underlay ... prior policy.” FCC v. Fox Television Stations, Inc., 129 S. Ct. at 1810. EPA’s decision to include a penalty provision in the Proposed Rule, given its prior defense of emissions averaging absent such a provision, is arbitrary and capricious.

Response: See response to EPA-HQ-OAR-2002-0058-2808.1, excerpt 30 for the discount factor.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 89

Comment: We agree that incorporating emissions averaging into the emission standards is a proper way to encourage flexibility and cost savings for affected facilities. There is ample precedent in the MACT program for allowing "bubbling" or emissions averaging. For example, the Pulp and Paper Chemical Recovery Combustion rule allows plants to set a PM emissions limit for each existing applicable process unit such that, if these limits are met, the total emissions from all existing process units are less than or equal to a "bubble" limit on all affected units. [See 66 Fed. Reg. 3180, 3184 (January 13, 2001) and 40 C.F.R. Part 63, Subpart MM. See also 67 Fed. Reg. 78046 (December 20, 2002) (proposing bubbling in the Lime Manufacturing rule).] Many other MACT standards have included emissions averaging provisions. See, e.g., 40 C.F.R. Part 63, Subpart JJJ (Group IV Polymers and Resins); 40 C.F.R. Part 63, Subpart U (Group I Polymers and Resins); 40 C.F.R. Part 63, Subpart G (Synthetic Organic Chemical Manufacturing Industry: Process Vents, Storage Vessels, Transfer Operations and Wastewater); 40 C.F.R. Part 63, Subpart LL (Primary Aluminum Reduction Plants); 40 C.F.R. Part 63, Subpart CC (Petroleum Refineries); 40 C.F.R. Part 63, Subpart EEE (Hazardous Waste Combustors).]

Under a bubble approach, each unit is assigned an enforceable permit limit and all permit limits, in the aggregate, must meet the standard. In contrast, in an emission averaging approach the source calculates its baseline emissions from regulated units, determines the net reductions that are required, and ensures that those emissions reductions are achieved through a combination of controls at regulated and unregulated sources. As such, greater recordkeeping and reporting requirements are associated with an emissions averaging plan, as compared to a bubble approach.

Bubbling and emissions averaging are well demonstrated techniques for meeting or exceeding environmental objectives at lower cost and with greater flexibility tailored to individual affected facilities. Provisions such as these allow plants to optimize their investments by installing controls on units where the lowest emission rates can be achieved in the most cost-effective manner possible. For example, a source could decide to over-control a newer unit in order to avoid costly investments in an older unit that may be retired before the useful life of the control device is reached. Bubbling provisions also provide environmental benefit by allowing for control options that minimize energy use. Energy efficient decisions benefit the environment by reducing power demands and the secondary pollutant impacts they generate.

Response: EPA acknowledges support of the emission averaging provision and has retained the emission averaging provision in the final rule.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 90

Comment: ACC concurs with EPA’s proposal and past precedent that use of the emissions averaging compliance alternative should be limited to existing units. New and reconstructed boilers/process heaters should be required to meet the more stringent "new source" requirements.

Response: We acknowledge the support and prior precedent. The final rule has retained the limitation of emission averaging provisions to existing sources.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 91

Comment: However, we believe that additional flexibility should be incorporated into the proposed emissions averaging provisions in this rule in order to ensure facilities have options to reduce the cost of compliance. The emissions averaging or bubble provision should be based on actual operating time and emissions and not capacity. Adding the element of time ensures equivalent control regardless of boiler operating schedules and provides flexibility with respect to the control strategy for limited use boilers. Some boilers are only used during maintenance outages, and incorporating flexibility into the emissions averaging provisions to accommodate limited use boilers will greatly reduce the compliance cost for these boilers. Boilers sharing common stacks should also be eligible for inclusion in the emissions averaging approach, especially if emissions can be measured from each boiler prior to the common stack. EPA has included all common stack units in its floor analyses by applying the measured common emission rate to each unit, instead of one time for the group of units, so this approach could also be used in an emissions averaging compliance scenario.

In addition, ACC believes that boilers of any design firing any fuel, and in any subcategory, should be included in the bubble and that facilities should not be limited to use of emissions averaging for boilers only in the same subcategory. There is no justification for restricting emissions averaging only to boilers in a specific subcategory; facilities should be able to average emissions from stoker boilers with emissions from pulverized coal boilers and liquid boilers. This approach has been used in several of the rules mentioned above. For example, the Pulp and Paper Chemical Recovery Combustion rule and the HON allow emissions averaging across different types of units. The equivalency by permit provisions in 40 CFR 63.94 allow sources to "trade" emissions from unregulated sources for emissions of regulated sources, so this is additional reason not to restrict use of emissions averaging to boilers within the same subcategory.

Response: See response to comment EPA-HQ-OAR-2002-0058-2694.1, excerpt 3, for response to actual vs. rated heat input capacity and a discussion of how units with common stacks can participate in the emissions averaging provision.
See response to comment EPA-HQ-OAR-2002-0058-3213.1, excerpt 175 for emission averaging between subcategories.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 92

Comment: ACC disagrees that a 10% penalty for use of emissions averaging is appropriate. This requirement restricts the utility of the proposed emissions averaging provisions, especially as this demonstration is proposed to be based on unit capacity and not actual unit operating data. The Pulp and Paper Chemical Recovery Combustion rule allows bubbling of emissions with no requirement to further reduce emissions to 90% of the allowable emission rate.

Response: See response to EPA-HQ-OAR-2002-0058-2808.1, excerpt 30 for the discount factor.

Commenter Name: Jim Griffin

Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 93

Comment: ACC believes that the application of the underlying principles of emissions averaging, as stated in this proposed rule, is sufficient to fully realize the statutory requirements that affected sources meet the standards, and that no discount factor is required. Moreover, EPA fails to justify the necessity to further tighten emissions standards when averaging is used. This point is further reinforced by the fact that EPA expressly excluded the provisions of emissions averaging, including the discount factor, to a situation where individual units are vented through a common stack. EPA must realize that there is no difference in actual emissions between two units emitting from separate stacks and the same units, operated in an identical fashion, emitting from a common stack. The quantity of contaminants emitted to the atmosphere will be identical in both circumstances and imposing a discount factor to the units emitting separately will discourage many facilities from using this compliance option.

EPA bases its justification for a discount factor on the emissions averaging provisions in this rule on the HON, stating that the legal basis and rationale for the HON emissions averaging provisions have been provided in the preamble to the final HON. [59 Fed. Reg. 19425 (April 22, 1994).] However, EPA dismisses this discount provision in the preamble to the proposed NESHAP rule for Plywood and Composite Wood Products (PCWP rule), stating:

...(the) HON sources have many emission points, are complex and diverse, and as a result are subject to a more complex set of emissions averaging provisions. The PCWP facilities have fewer emission points within each facility. Therefore, the enforcement concerns arising due to the large number of emission points in each HON facility are minimized for PCWP facilities." [68 Fed. Reg. 1290 (January 9, 2003).] EPA concludes its argument to dismissing a discount factor for PCWP sources by stating that "...(the) HON requires a discount factor of 10 percent in credit calculations to share with the environment some portion of the cost savings due to emissions averaging and to account for uncertainty in emissions estimation. Due to differences between PCWP and HON sources (discussed below), we do not believe it is necessary for the proposed PCWP rule to include a discount factor.[68 Fed. Reg. 1290 (January 9, 2003).]

This conclusion was maintained in the final version of the PCWP rule. [69 Fed. Reg. 45973 (July 20, 2004).] In fact, the concept of imposing a discount factor on the use of emissions averaging was never discussed neither in the initially proposed [68 Fed. Reg. 1660 (January 13, 2003).] nor the 2004125 Boiler rule. Thus, imposing a discount factor to the emissions averaging compliance alternative is unwarranted and unjustified.

Response: See response to EPA-HQ-OAR-2002-0058-2808.1, excerpt 30 for the discount factor.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1

Comment Excerpt Number: 94

Comment: ACC recommends that sources be given the flexibility to use emissions averaging provisions or include alternative bubble emission limits for dioxin as well as for PM/TSM, HCl, and mercury. For dioxin, which is a concentration based limit and not a mass based limit, the source would calculate its recommended alternative bubble limits using an approach similar to that included in the Pulp and Paper Chemical Recovery Combustion rule for the PM limits in gr/dscf, and these bubble limits would be submitted to the permitting authority for approval and inclusion in the air permit. The alternative bubble limits would be set during the initial compliance test. Separate alternative bubbling calculations could be submitted for PM, total metals, mercury and/or HCl at the discretion of the applicant. A bubbling plan need not include all pollutants; and for any pollutants not specifically included in the bubbling plan, the applicable rule's emissions limitations would apply as a default.

An equation on page 65 of the submittal could be used to define this averaging methodology:

Where:

Ave Weighted Emissions = Average weighted emissions for Dioxins/Furans, in concentration units (ng/dscm (TEQ) corrected to 7 percent oxygen);

Ec = Emissions rate, as calculated expressed in ng/dscm (TEQ) corrected to 7 percent oxygen;

Fg = Stack volumetric flow rate

Response: See response to comment EPA-HQ-OAR-2002-0058-2801.1, excerpt 36 for discussion of pollutants eligible for emissions averaging and EPA-HQ-OAR-2002-0058-2694.1, excerpt 6 for response to comments establishing site-specific alternative dioxin limits.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 95

Comment: The proposed rule contains a requirement for the facility to demonstrate each month that the average weighted emissions of the boilers included in the emissions averaging scheme are below the applicable emission limit using the actual heat inputs for that month. ACC believes that an annual determination that the emissions averaging or bubble limits are being met is more than satisfactory to ensure protection of public health and welfare and appropriate for consideration for a technology-based MACT standard.

Response: See response to EPA-HQ-OAR-2002-0058-3213.1, excerpt 180 for response to comment on monthly compliance determinations.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 96

Comment: The first compliance demonstration should not be required immediately after the rule compliance date, as maintenance and outage schedules may make it hard for a facility to comply with the emissions averaging provisions without 12 full months of data. Other rules do not require a monthly test (e.g., the HON), but provide a 30 percent allowance during each quarter and equivalency on an annual basis. Although a year is an appropriate period for determining the time-weighted average emissions rate, consideration may be given for convenience sake to a shorter 6 month period that coincides with the required reporting period for the standard. It is expected that a 6 to 12 month period would provide the flexibility needed to retain the benefit of the recommended averaging or bubbling provisions. [69 Fed. Reg. 55218 (September 13, 2004).]

Response: See response to EPA-HQ-OAR-2002-0058-2824.1, excerpt 23 for response to comment on timing of first compliance demonstration.

Commenter Name: Michael A. Livermore
Commenter Affiliation: Institute for Policy Integrity, New York University School of Law
Document Control Number: EPA-HQ-OAR-2002-0058-2720.1
Comment Excerpt Number: 15

Comment: EPA Should Fix Errors in the Discounting Formulas for Emissions Averaging

For the Major Source Rule, EPA is proposing to allow emissions averaging within a regulated source over its existing individual boilers in the same category. This is being proposed as a flexibility mechanism because emissions reductions may be cheaper at a particular unit. This proposal is subject to several conditions including an "emissions averaging plan" and a cap on the overall emissions level. [Footnote: 75 Fed. Reg. at 32,034-35.] In addition to these other safeguards, EPA is proposing a discount factor of ten percent to "ensure that averaging will be at least as stringent." [Footnote: 75 Fed. Reg. at 32,035] The agency is requesting comment on "use of a discount factor and whether ten percent is the appropriate discount factor." [Footnote: 75 Fed. Reg. at 32,035]

While the practical effect of this is not clear from the preamble, it is possible to discern its impact from the proposed regulatory language. Section 63.7522(d) of the proposed rule states that the "The averaged emissions rate from the existing boilers and process heaters participating in the emissions averaging option must be in compliance with the limits in Table 2 [emissions limits for existing sources] to this subpart at all times following the compliance date. . . ." [Footnote: 75 Fed. Reg. at 32,053]

Section 63.7522(e) then gives two alternative formulas to demonstrate initial compliance. According to these formulas, the average emissions rate used to determine compliance is only 90% of the actual weighted average emissions rate (in this case, weighted by the maximum rated heat input capacity). Subsequent to this, each entity must demonstrate compliance on a monthly basis according the formulas laid out in Section 63.7522(f). [Footnote: 75 Fed. Reg. at 32,053-54] Similarly to the formulas for initial compliance, the average emissions rate here is also only 90% of the actual weighted average emissions rate (weighted here by actual heat input).

These formulas appear to be mistaken and, instead of multiplying by 0.9, they should be multiplying by 1.1 (or dividing by 0.9). To see the error in the formulas, the simplest case can be considered. If there are two boilers at the same facility with identical heat input capacity and actual monthly heat input, then instead of a weighted average the formulas reduce to a simple average. Thus, if both actual emission rates for a given pollutant are 1, then the simple average emission rate is 1. This figure is then multiplied by 90%, giving an emissions rate of 0.9 for the purposes of regulatory compliance. Obviously, the result of the formula is a lower emissions rate than the actual correct weighted average. This seems directly contrary to the stated purpose of the discounting provision and should be fixed by EPA.

If the formulas are corrected to be in accord with the stated purpose of the discounting provision, there will be several effects from discounting. By penalizing averaging, it disincentivizes sources from using this option. This will lead to fewer cost savings, which is the goal of allowing averaging in the first place. However, averaging may lead to fewer reductions in emissions and thus fewer benefits to the general public. The net effect of this is ultimately an empirical one. If the agency is under-regulating (as seems likely, see supra pp. 8-9), then the decrease in emissions reductions is unwarranted and not worth the reduced costs. However, if the standards are set efficiently (as we argue they should be), this should be unnecessary unless it is motivated by other concerns (such as measurement error).

EPA should have an independent justification for any discounting provision that explains why it should be implemented and not just what its effects are. It is impossible to determine what the proper discount factor should be without knowing the provision’s purpose. The justification of ensuring stringency could equally well justify a discount factor of 5%, 10%, or 20%.

Response: See response to EPA-HQ-OAR-2002-0058-2808.1, excerpt 30 for the discount factor.

Switching Subcategories

Commenter Name: Michael G. Dowd
Commenter Affiliation: Virginia Department of Environmental Quality, Air Division
Document Control Number: EPA-HQ-OAR-2002-0058-2631.1
Comment Excerpt Number: 3

Comment: VADEQ would like EPA to provide implementation guidance for establishing the boiler's initial fuel subcategory as well as procedures for various fuel switching scenarios so that state and local programs will be equipped to implement the rule when promulgated. In particular, VADEQ seeks EPA implementation guidance on the following issues:

* In the proposed rule, the boiler's fuel subcategory is based on the boiler type and percentages of fuel used on an annual average heat input basis. For existing boilers, what initial time period should a facility use to determine what fuel emission standards must be met? VADEQ recommends the 12 month period prior to the compliance date for determining the boiler's fuel subcategory.
* Will facilities be able to switch fuels and become subject to a different standard? If so, when would the facility become subject to the new standard and when would they need to show compliance? VADEQ supports facilities being able to switch fuel and become subject to a different standard. VADEQ suggests that when the fuel burned in the boiler meets the definition of the new fuel category based on the rolling annual average heat input basis, the boiler should then be subject to the new standards and compliance demonstrated within 180 days.
* Can boilers go back and forth between fuel subcategories or does, "once in, always in" apply? VADEQ supports allowing fuel switches as long as the process for doing so is clear.
* Can a boiler go from a fuel subcategory with emission limits to a subcategory without emission limits, for example switching from distillate oil to only natural gas?

Response: The definitions for the liquid and gas fuel subcategories refer to a percentage heat input for a given type of fuel determined on an annual average. EPA agress that the relevant subcategory should be based on the 12 months immediately preceding the compliance date for existing sources. EPA is adding provisions to the regulations that discuss how to switch subcategories as a result of a fuel switch. A facility would become subject to the new standard on the effective date of the fuel switch and they must provide 30 days notice before switching fuels, if that fuel switch will result in a change in subcategory. Boilers will be allowed to go back and forth between fuel subcategories, but must do so in a way that does not compromise their or our ability to assess the continuing compliance status of the facility. As such sources must not switch fuel subcategories more frequently than once every 30 days after the initial test that demonstrates compliance.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 24

Comment: In order to stay in business and/or minimize costs, many boilers and process heaters will opt to change fuels to Gas 1 prior to the compliance date of this regulation. In that case, the past year‘s fuel would not be the appropriate basis for a unit‘s initial subcategory assignment.

Recommendation: Where a source commits to meet the Gas 1 source category definition before the rule compliance date for a particular boiler or process heater, provision should be provided to assign that boiler or process heater to the Gas 1 subcategory until one calendar year of fuel use data after the compliance date is available.

Response: The definitions for the liquid and gas fuel subcategories refer to a percentage heat input for a given type of fuel determined on an annual average. The 12 months immediately preceding the compliance date for existing sources would be used to determine the annual heat input and the applicable subcategory. However, the commenter raises an important point. If the source intends to switch fuels within the 12 months immediately preceding the compliance date, consistent with the intent of the provisions that EPA has added to the regulations that allow for a switch in subcategories as a result of a fuel switch, the source may switch fuels up until just before the compliance date, if the source provides advance notification of their intent to switch fuels, consistent with the notification provisions added to the final rule.

Commenter Name: Leonard W. Sandridge
Commenter Affiliation: University of Virginia
Document Control Number: EPA-HQ-OAR-2002-0058-2769.1
Comment Excerpt Number: 30

Comment: What are the ramifications if we plan to fire less than 10% oil in a boiler but then go over this amount? Can the compliance approach vary from year to year – one year gas, one year oil? Our fuel selection is based on a variety of factors including price, maintenance requirements, and the need to turnover the oil tank contents routinely. We recommend that if a boiler has the intent of meeting the definition of a gas 1 subcategory but exceeds the oil usage restriction as documented during a semiannual report, that during the subsequent 6 month period a compliance demonstration be completed (either through stack testing or fuel analysis) such that the next semiannual report documents compliance with the liquid subcategory emission standards.

Response: Once the applicability to a given subcategory is determined, the source must remain in compliance with all the terms of that subcategory including the defined type and amount of fuel that is to be combusted for that subcategory, and all the associated emission limitations and associated monitoring, recordkeeping and reporting requirements for the subcategory. However, EPA is adding provisions to the regulations that discuss how to switch subcategories as a result of a fuel switch. Upon switching subcategories, the new subcategory definitions would apply to the source.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 53

Comment: As we pointed out previously, there are also a great many practical and regulatory issues associated with having two gas subcategories. Individual boilers and process heaters can move, often for unplanned reasons, between the gas subcategories. Revising the definitions of the subcategories as recommended previously will help limit these occurrences, but will not eliminate them. A Gas 1 operation may shift to a Gas 2 operation because of construction of a new process unit that generates gas, thereby backing out natural gas from some combustion sources, or a Gas 2 unit may become a Gas 1 unit because a gas producing unit is shut down. Even with the Gas 1 and 2 definition changes we recommend, it is not out of the question that more than 10% of the firing in a calendar year of a particular unit will be from the Gas 2 category, just due to operating variability as streams are mixed. Every time a gas-fired unit changes subcategory, there will be permitting and compliance issues and, in transitioning from the Gas 1 to the Gas 2 requirements, major investments.

Response: The 12 months immediately preceding the compliance date for existing sources would be used to determine the annual heat input and the applicable subcategory. EPA is adding provisions to the regulations that discuss how to switch subcategories as a result of a fuel switch.

Commenter Name: Michael Potter
Commenter Affiliation: Goodyear Tire and Rubber Company
Document Control Number: EPA-HQ-OAR-2002-0058-3181
Comment Excerpt Number: 2

Comment: Goodyear has boilers with capability to fire either natural gas or fuel oil. These boilers could be included in either the Gas 1 subcategory or the liquid fuel subcategory depending on the portion of annual heat input provided by the liquid fuel. Historically this proportion has varied significantly from year to year, and from plant to plant.

Response: The definitions for the liquid and gas fuel subcategories refer to a percentage heat input for a given type of fuel determined according to the relative annual heat input of each fuel type. The 12 months immediately preceding the compliance date for existing sources would be used to determine the annual heat input and the applicable subcategory. EPA is adding provisions to the regulations that discuss how to switch subcategories as a result of a fuel switch.

Commenter Name: Gordon M. Smith
Commenter Affiliation: Mitsubishi Polyester Film, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2912
Comment Excerpt Number: 5

Comment: The subcategories of boilers and process heaters to which the proposed rule applies are listed in §63.7499. Gas- and liquid-fired boilers and process heaters can often change fuels with little or no equipment modification. For instance, units with both liquid and gas capability can move from gas to liquid with simple fuel realignments.

The movement of a unit from a gas subcategory to the oil subcategory and vice versa must be addressed. This can happen because of changes in fuel economics or due to fuel delivery interruptions. In this case we also request three years be allowed for the unit to re-permit and to comply with the new set of requirements.

Response: The definitions for the liquid and gas fuel subcategories refer to a percentage heat input for a given type of fuel determined on an annual average. The 12 months immediately preceding the compliance date for existing sources would be used to determine the annual heat input and the applicable subcategory. EPA is adding provisions to the regulations that discuss how to switch subcategories as a result of a fuel switch. There are no compliance extensions available beyond the specific extension allowed for in Section 112(i). EPA has already provided the three year extension in setting the initial compliance date for this rule. Source may request an additional year extension and these requests will be considered on an case-by-case basis.

Commenter Name: John Steber
Commenter Affiliation: Performance Fibers
Document Control Number: EPA-HQ-OAR-2002-0058-3174
Comment Excerpt Number: 7

Comment: Should heat input be based on a rolling 12-month average rather than an annual average — PFI believes that the use of a 12-month rolling average would allow facilities (and regulators) to monitor and assess its subcategory status more easily throughout the year and provide a better indicator than an end-of-year type of evaluation.

Response: EPA agrees that the heat input should be based on a 12 month average instead of a calendar year annual basis. A source attempting to establish which subcategory applies using the heat input criteria would base its determination on the immediately preceding 12 months of operation. The 12 month period immediately preceding the compliance date of the standard would be used to determine the appropriate subcategory for the unit. EPA is adding provisions to the regulations that discuss how to switch subcategories as a result of a fuel switch.

Commenter Name: Daniel Moss
Commenter Affiliation: Society of Chemical Manufacturers and Affiliates
Document Control Number: EPA-HQ-OAR-2002-0058-2926.1
Comment Excerpt Number: 7

Comment: EPA should also clarify over what annual averaging period the 90% heat input basis calculation should be performed: Rolling 12 months? Calendar year? Last 5 years? Last 10?

SOCMA recommends that EPA specify a five-year annual averaging period, so that facilities' calculations align with other determinations that they make for Title V permitting purposes.

Response: The annual heat input basis used in the subcategory definitions is based on an annual average for the immediately preceding 12 month period. A source attempting to establish which subcategory applies would base its determination on the immediately preceding 12 months of operation. The 12 month period immediately preceding the compliance date of the standard would be used to determine the appropriate subcategory for the unit. EPA is adding provisions to the regulations that discuss how to switch subcategories as a result of a fuel switch.

Commenter Name: Michael Potter
Commenter Affiliation: Goodyear Tire and Rubber Company
Document Control Number: EPA-HQ-OAR-2002-0058-3181
Comment Excerpt Number: 7

Comment: Emission limits should apply only when burning the fuel for which the limit was developed.

The definition of liquid fuel subcategory clearly acknowledges that the boiler owner/operator may burn fuel other than a liquid fuel in a liquid fuel subcategory boiler. In the case of a natural gas fired boiler that may also use fuel oil to provide more than 10 percent of the annual heat input, the boiler would need to be equipped with control equipment adequate to achieve the liquid fuel subcategory emission limits in Table 2 when burning oil. However, the control equipment is not only expensive to purchase and install, but is also expensive to operate, and controls should not be required to operate when only natural gas is being used. For example, the liquid fuel category standard limits carbon monoxide (CO) emissions to 1 ppm adjusted to 3 percent oxygen. However, there is no CO limit or any other numerical emission limit applicable to boilers that only burn natural gas. In order for the liquid fuel subcategory boiler to achieve the 1 ppm limit when burning only natural gas, the excess air used in the boiler would need to be unusually high leading to lower boiler efficiency. The lower boiler efficiency, in turn would require use of more natural gas. This is clearly at odds with the proposed requirements in Table 3 regarding conducting an energy assessment.

Additionally, add-on control equipment uses extra energy to operate. Unnecessary usage of the add-on control equipment wastes energy, contrary to the intent of the energy assessment requirement. Further, the CO limit is not a reasonable limit when burning natural gas because the CO limit is a surrogate for organic HAP emissions from fuel oil that are not likely to occur when burning natural gas.

Based on the foregoing, Goodyear believes the proposed regulations should be revised to specify that the emission limits will apply only when burning the fuel for which the limits were developed, or at least to specify that no numerical emission limits should apply when burning only Gas 1 fuels regardless of the subcategory that applies to the boiler.

Response: EPA disagrees with the commenter. The emission limits apply to each subcategory and the subcategories are based on an annual basis. Gas 1 units that fire liquid under the limited circumstances allowed for curtailment and periodic testing are still considered gas 1 units and are not subject to emission limits while firing liquid. We have added provisions to the final rule to allow units to switch subcategories based on the immediately preceding 12 months of operation.

Commenter Name: Michael Potter
Commenter Affiliation: Goodyear Tire and Rubber Company
Document Control Number: EPA-HQ-OAR-2002-0058-3181
Comment Excerpt Number: 8

Comment: The proposed standards should allow a boiler to undergo a change in applicable subcategory with adequate time allowed to install necessary control equipment.

Proposed 40 CFR section 63.7495(c)(2) specifies that existing boilers at HAP area sources that become HAP major sources must comply with the requirements within three (3) years after the source becomes a major source. Goodyear believes there may be situations where existing boilers with both gas and oil firing capability that intend to limit themselves to less than 10 percent oil firing may later find it necessary to opt into the liquid fuel subcategory. Consequently, Goodyear believes that 40 CFR section 63.7495 should be revised to provide such a boiler adequate time to install needed controls.

Response: The rule has been amended to clarify that sources may move between subcategories. EPA is providing sources the flexibility to choose the effective date for a fuel switch, and is allowing for an unlimited number of fuel switches . Procedures have been developed to provide this flexibility while not compromising our ability to determine compliance with the standards. The procedures allow facilities to build as much time into coming into compliance with the new subcategory as sources deem necessary. However, sources must remain in compliance with their currently applicable subcategory at all times, are expected to be in compliance with the new subcategory on the date identified in the notification, and are not allowed to operate out of compliance with the currently applicable subcategory while they install controls. After expiration of the initial compliance deadlines in 63.7495, sources are expected to be in continuous compliance with an applicable boiler MACT subcategory. There are no provisions for extensions of compliance beyond the three years already provided in the regulation and the case by case extensions for installation of controls. Consistent with 63.6(i)(4)(i)(B), requests for a one year extension for installation of controls must be submitted no later than 120 days prior to the affected source's compliance date.

Commenter Name: American Crystal Sugar Company and Michigan Sugar Company
Commenter Affiliation: Patricia Hansen and Steven Smock
Document Control Number: EPA-HQ-OAR-2002-0058-2970.1
Comment Excerpt Number: 20

Comment: The agency needs to clarify the subcategory classification. For a boiler with an unchanging or small changes in the fuel fired, the definitions of the subcategories are straight forward. However some boilers do have significant changes in the fuel utilized in a given year or more. For example, some boilers can fire liquid or natural gas (or several other combinations). Depending on the market it may fire 100% natural gas or 100% liquid fuel or some mix of the two in a given year. It is clear that in any year that the boiler's heat input exceeds 10% from a liquid fuel the boiler is a liquid fuel boiler for that year. However; how is the boiler classified during the year(s) if it fires only natural gas? Additionally, would this classification be affected if the boiler's operational period does not match the calendar year? For the Sugar Beet industry the operational year (and generally fiscal year) is from early fall to late spring. The range of operation is from —90 to —260 days.

Response: A source needs to identify, in the Notification of Compliance Status under 63.9(h)(2)(ii) and 63.7545(e)(1), the subcategory the source is in. The subcategory classification is based on the 12 month period immediately preceding the compliance date of the standard. However, sources with dual firing capability may pick which subcategory they intend to comply with, and must continue to comply with the provisions in that subcategory until such time as they become subject to a new subcategory, consistent with the procedures for fuel switches which have been added to the rule. The source would notify the Agency of its intended subcategory in the initial notification required in 63.9(b)(2). If the source intends to switch subcategories prior to the initial compliance date, it must provide advance notification, consistent with the procedures added to the regulation. The rule has been amended to clarify that sources may move between subcategories consistent with the procedures promulgated.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 222

Comment: EPA should propose for comment how and when units would move between subcategories in the rule based on the actual fuel mix fired and how and when compliance would be demonstrated for a different subcategory than the one the unit was under for the initial compliance demonstration.

Response: The rule has been amended to clarify that sources may move between subcategories and has promulgated procedures that provide flexibility to sources while not compromising their and our ability to determine continuing compliance with the standards. The procedures specify compliance and testing obligations.

Common Stack Provision

Commenter Name: Steven M. Maruszewski
Commenter Affiliation: The Pennsylvania State University
Document Control Number: EPA-HQ-OAR-2002-0058-2729.1
Comment Excerpt Number: 13

Comment: Common Stack - Start-up / Shut down
Penn State understands that the applicable sections of 40 CFR 63 were vacated and that 24 hour and 30 day averaging is included in the draft regulation. The University's concern is that during the start of our heating season, we will likely bring on all four boilers at the West Campus Steam Plant sequentially over a short period of time. All four boilers are ducted to a single stack. The CO monitor installed in that single stack will measure significant startup levels of CO during a comparatively short time span. The reverse of this process will happen at the end of the heating season. The University is requesting that there be an accommodation for such process when multiple sources are ducted to a common stack. [Attachments 3b and 3c in the submittal clearly show this relationship.]

Response: EPA has provided a work practice during periods of start up and shutdown in the final rule. See the preamble for a final discussion of startup and shutdown.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 153

Comment: It is not uncommon for boilers or process heaters to share a common stack or to be located very close together. The proposal recognizes the common stack situation and addresses monitor configurations for such situations. One efficiency item that is not addressed is the potential sharing of analyzers and we request that be added in the final rule. CO and O2 CEMS are rapid response instruments and thus can sometimes be shared, particularly where multiple sources share a common stack, while easily meeting the requirement for obtaining data at least every 15 minutes.

Recommendation: Allow sharing of CEMS as long as the data frequency and other CEMS requirements are met.

Response: It is possible that sample conditioning systems and analyzers can be shared where multiple sources share a common stack, provided the common stack, data frequency and other CEMS requirements are met. Sources should describe how they will meet the monitoring requirements in the site-specific monitoring plan developed for this rule as specified in §

63.7505(d) and 63.8(e). It is noted that CO CEMS requirements have been removed from the final rule.

Commenter Name: David Bonistall
Commenter Affiliation: NewPage Corp
Document Control Number: EPA-HQ-OAR-2002-0058-2920.1
Comment Excerpt Number: 35

Comment: Our Luke Mill operates three boilers, two of which are coal fired and the third unit is a natural gas unit. All three boilers discharge into a common stack. The common stack requirements contained in § 63.7522 are of interest to us but we have some concerns with the proposal.

We believe that boilers of any design firing any fuel (e.g., in any subcategory) that vent through a common stack need to be included in the common stack provision. We do not believe there is any justification for restricting the common stack emission averaging provisions only to boilers in a specific subcategory; facilities need to be able to average emissions from all types of boilers that vent to a common stack. In addition, the performance test needs to be completed when all units are venting to the common stack as they usually do. The shutting down of a boiler/unit or venting to another stack in order to complete a performance test could cause significant operational issues for a facility.

Response: The provisions of 63.7522(j), which are part of the common stack provisions, allow for emissions averaging between different subcategories. Emissions from a nonaffected unit cannot be included in the compliance determination for the MACT rule. As such, the rule requires at 63.7533(j)(2) that if nonaffected units vent to the common stack, the nonaffected units must be shut down or vented to a different stack during the performance test. EPA notes, however, there is a typo in that provision which states, "If affected units from nonaffected units vent to the common stack..." when it should read, "If affected and nonaffected units vent to the common stack..." EPA has made this correction. Emissions avergaing is only a compliance option, so if shutting down nonaffected units creates significant operational problems for the facility, and if the facility cannnot or will not vent those emissions to another stack, then emissions averaging may not be a preferable option for the facility.

Commenter Name: David Bonistall
Commenter Affiliation: NewPage Corp
Document Control Number: EPA-HQ-OAR-2002-0058-2920.1
Comment Excerpt Number: 36

Comment: We believe units venting to a common stack need to be allowed to average emissions for all Boiler MACT pollutants. The proposed rule language is not clear if the common stack requirements allow emission averaging for all of the Boiler MACT pollutants. Units that vent to a common stack should not be limited to just averaging particulate matter, HC1 and mercury.

Site-specific situations may not allow for satisfactory monitoring locations in the ducting or breaching prior to reaching the common stack.

Response: EPA has developed several compliance flexibilities in this rule, and treatment of common stacks and the emissions averaging provision are two of such compliance flexibilities. Facilities whose sources vent to a common stack and want to use the emissions averaging provision are also subject to the discount factor. Facilities that opt to comply with the provisions set forth for common stacks without using emissions averaging are not subject to a discount factor. The requirements and language of the common stack option are a result of an earlier focused Agency reconsideration and the resulting public comments received on that reconsideration (See 71 FR 70651). The common stack introduces testing flexibility since testing emissions from a common stack for a group of boilers would be equivalent to the average emissions calculated from individual stack tests on each unit contributing to the stack emissions. Testing once per stack reduces the testing costs associated with boilers venting to the same stack. The scope of applicable sources is very narrow since not all units at a facility vent to a common stack. The emissions averaging option introduces a broader compliance flexibility, and since some units may opt to over control some sources while undercontrolling other sources in order to stategically allocate capital for control devices. EPA determined that given prior precedence for a discount factor in emissions averaging situations, and the broader impact emission averaging has on similar units across a facility, that a discount factor remains appropriate. Further, in many cases EPA notes that more than one of these compliance flexibilities is available to regulated entities.

Commenter Name: Chris M. Hobson
Commenter Affiliation: Southern Company
Document Control Number: EPA-HQ-OAR-2002-0058-2741.1
Comment Excerpt Number: 65

Comment: The proposed emissions averaging procedures do not apply when unaffected units or units in different subcategories are ducted to a common stack. As EPA states in the Preamble, these units are excluded because it is not possible to distinguish the emissions from each individual unit.

This issue was addressed in EPA's reconsideration of the emissions averaging provisions under the vacated Rule. In the vacated Rule, EPA permitted such units to be included in the averaging plan with the requirement that emissions from the affected units in other subcategories or non-affected units be shut off or vented to a different stack during testing. This clearly allows emissions to be quantified from all units in the emissions averaging group, and, therefore, should be allowed under the current IB MACT Rule as well. Likewise, the same requirements should be included for common stack units that are not included in an averaging plan.

Response: The common stack provisions in the emissions averaging procedures do allow for averaging among affected units even if there are unaffected units that can vent to the common

stack, if the emissions from the non-affected units are shut down or vented to a different stack during the performance test. See 63.7522(j)(1)&(2).
Affected units that share a common stack do not have to take part in emissions averaging. If units that are subject to different subcategories are able to monitor compliance separately, we encourage them to do so. The test plan and site-specific monitoring plans required to be submitted under 63.7(c) and 63.7505(d) need to address how these units will conduct the performance tests and monitor.

Commenter Name: Traylor Champion
Commenter Affiliation: Georgia-Pacific LLC
Document Control Number: EPA-HQ-OAR-2002-0058-2745.1
Comment Excerpt Number: 56

Comment: Within the emissions averaging options at §63.7522(h), EPA has defined certain compliance alternatives for a common stack configuration – where more than one boiler shares a common stack. EPA has properly stated the requirements in §63.7522(i) for two or more boilers in the same subcategory, each of which vents through a common control device to a common stack. However, EPA's language in §63.7522(j) appears to be intended, but is not crystal clear, for another common configuration – where there are two or more boilers in the same subcategory, each of which vents through its own control device to a common stack.
GP's Muskogee Mill Configuration
GP's tissue mill at Muskogee, OK has two coal-fired boilers, each with its own baghouse that vents to a common stack (Stack 3) that has a common opacity monitor.
(See submittal for a sketch a these boilers)
Any stack testing on these boilers must be done in the common stack – testing in the ductwork from the baghouses to the common stack would not meet the required upstream and downstream distances for test ports in EPA testing methods.

40 CFR 63.7522(j) needs to be clarified to cover the Muskogee configuration

This language does not specifically cover the Muskogee situation where two boilers in the same subcategory vent into a common stack and it is not possible to test each unit individually. However, Equation 6 could also be used if two or more boilers emitted to the common stack and are in the same subcategory (the emission limit would merely be the same) and would cover the configuration at Muskogee and probably other mills.

GP urges EPA to change the language in §63.7522(j)(1) to read (changes in bold):
(1) Conduct performance tests according to procedures specified in § 63.7520 in the common stack if affected units from the same subcategory or other subcategories vent to the common stack. The emission limits that the group must comply with are determined by the use of equation 6...

Response: Section 63.7522 has beed edited to specifically clarify that situations where the exhaust of affectes units are each individually controlled and then sent to a common stack may utilize the common stack provisions of 63.7522(j).

Compliance Dates

Commenter Name: Houston Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1876
Comment Excerpt Number: 53

Comment: Impose an adequate timeline for compliance. EPA has proposed a three-year compliance timeline for sources. We believe that this timeline is in adequate due to the number of effected sources and the engineering solutions available to industry.

Response: Regarding the commenter's concerns on a reasonable implementation schedule, see response to comment EPA-HQ-OAR-2002-0058-2702.1, excerpt 218.

Commenter Name: John Williams
Commenter Affiliation: Maine Pulp and Paper Association
Document Control Number: EPA-HQ-OAR-2002-0058-1913.1
Comment Excerpt Number: 12

Comment: Compliance Deadline. The compliance deadline must be extended. There is no way that the necessary testing can be performed, the control systems engineered and the equipment required to meet these standards be produced, installed and started up in a 3-year timeframe for the thousands of sources affected across the country.

Response: Regarding the commenter's concerns on a reasonable implementation schedule, see response to comment EPA-HQ-OAR-2002-0058-2702.1, excerpt 218.

Commenter Name: Don Grimm
Commenter Affiliation: Hood Industries, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2352
Comment Excerpt Number: 17

Comment: It is apparent that owners and operators will be required to retrofit countless industrial boilers and process heaters in order to meet the final rule. The proposal would set a three-year compliance deadline for existing affected sources. However, this is an exceedingly short time given the extensive nature of the needed retrofits and the limited technical resources available to accomplish the retrofits (especially in light of the fact that industrial boiler owners will be competing for equipment and technical resources with other key industry sectors such as the utility sector, which will have a similar compliance deadline for the utility MACT and also will be required to install substantial air pollution controls to meet the proposed Clean Air Transport Rule).

To solve this problem, EPA must adopt a significantly longer compliance deadline. Nominally, EPA should adopt by rule an across-the-board one-year extension pursuant to § 112(i)(3)(B). However, even a four-year compliance period will be inadequate for many affected sources. Therefore, EPA should provide additional time by: (1) granting in the final rule a Presidential extension under § 112(i)(4), given that it is in the "national security interests of the United States" to prevent widespread noncompliance in the industrial base; (2) declaring that the statutory three-year compliance period is impossible to meet or otherwise produces "absurd results," which as demonstrated in EPA's recent PSD Tailoring Rule are doctrines that allow EPA to depart from clear statutory directives in appropriate circumstances; and/or (3) establishing phased or sequenced requirements such that certain element of the rule become effective no later than three years after promulgation (thus satisfying § 112(i)(3)(A)), while others are phased in at later times.

Response: Regarding the commenter's concerns on a reasonable implementation schedule, see response to comment EPA-HQ-OAR-2002-0058-2702.1, excerpt 218.

Commenter Name: Steven M. Maruszewski
Commenter Affiliation: The Pennsylvania State University
Document Control Number: EPA-HQ-OAR-2002-0058-2729.1
Comment Excerpt Number: 4

Comment: The planning, permitting, installation and compliance testing all within a three year time frame is unattainable. It has been our experience that permitting significantly less complex projects has taken in excess of 24 months. Facilities will be competing with other industries for qualified professionals, compliance equipment and stack testing services. This difficulty will be magnified when the Utility Boiler MACT is published in Spring 2011. In colder climate regions, the stack testing windows are shorter and make the schedule even more compact.

Response: Regarding the commenter's concerns on a reasonable implementation schedule, see response to comment EPA-HQ-OAR-2002-0058-2702.1, excerpt 218.

Commenter Name: James P. Brooks
Commenter Affiliation: Maine Department of Environmental Protection, Bureau of Air Quality
Document Control Number: EPA-HQ-OAR-2002-0058-2746.1
Comment Excerpt Number: 15

Comment: Due to the broad scope of both the Area and Major Source Boiler MACTs, there will be significant demand for stack testing and installation of monitoring and control equipment. The Maine DEP is concerned that there will an insufficient supply of qualified testing companies to meet this demand within the proposed timeframes. We recommend that EPA allow one year for facilities to conduct initial compliance testing instead of the proposed 180 day period. We are also concerned that existing major sources will be unable to install the necessary control and monitoring equipment within three years. There will be high demand and limited supply for the required equipment, and many facilities will need to undertake significant designing, planning and construction to locate the equipment within the existing facility. We recommend that EPA establish a compliance date five years from the date the final rule is published.

Response: Regarding the commenter's concerns on a reasonable implementation schedule, see response to comment EPA-HQ-OAR-2002-0058-2702.1, excerpt 218.

Commenter Name: G. Vinson Hellwig and Robert H. Colby
Commenter Affiliation: National Assocation of Clean Air Agencies
Document Control Number: EPA-HQ-OAR-2002-0058-2841.1
Comment Excerpt Number: 32

Comment: The proposed rules will create additional resource burdens on state and local permitting agencies that will have to issue several thousand Title V permit revisions, draft emission control regulations and submit them to EPA for review and approval under section 111 of the CAA. EPA can mitigate the burdern on state an local permitting agencies by specifically set out its expectations of state and local permitting authorities and incorporate reasonable timelines in its implementation schedule.

Response: EPA acknowledges the concerns of state governments but notes that although there are over 13,000 estimated boilers and process heaters, only approximately 1,500 boilers at approximately 700 facilities are subject to emission limits. The remaining units demonstrate compliance with the standard using work practice standards allowed for small, gas-fired, and limited use units. This is expected to reduce the burden on state and local permitting agencies. Regarding the commenter concerns on a reasonable implementation schedule, see response to comment EPA-HQ-OAR-2002-0058-2702.1, excerpt 218.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 263

Comment: Even under the best of circumstances, a major retrofit of a boiler takes years from project start to finish. EPA has estimated that the installation of an activated carbon injection control system on one combustion unit – a comparatively simple installation – takes about 15 months. (EPA, Engineering and Economic Factors Affecting the Installation of Control Technologies for Multipollutant Strategies (2002).) However, EPA expects a range of control devices will be used to meet the standards, including fabric filters, activated carbon injection, electrostatic precipitators, wet scrubbers, replacement burners, and combustion controls. EPA, Regulatory Impact Analysis: National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters, 3-1 (April 2010) ("The control analysis considered fabric filters, carbon bed adsorbers, and activated carbon injection to be the primary control devices for mercury control, electrostatic precipitators for units meeting mercury limits but requiring additional control to meet the PM limits, wet scrubbers to meet the HCl limits, tune-ups, replacement burners, and combustion controls for CO and organic HAP control, and carbon injection for dioxin/furan control.") Further, the sheer number of boilers impacted by the rule will make finding – and then scheduling – the design and construction resources almost impossible. EPA estimates that there are approximately 13,555 units located at 1,608 facilities covered by this rule. 75 Fed. Reg. 32048. Given that EPA has set emissions standards that only a handful of existing units can currently meet, almost every single existing unit subject to an emission standard will need to be retrofitted. Retrofits will also be required to hundreds or thousands of area source boilers and units covered under the revised CISWI rule. Boiler owners will need to hire consultants to assist them in designing and performing the retrofit. Thus, across the multitude of industries impacted by this rule, boiler owners will be scrambling to find the very few qualified consultants who can perform the retrofits necessary to make boilers compliant with this stringent rule. There are a limited number of consulting companies with the expertise to assist in such retrofits, and they will likely be unable to assist all of the boiler owners in less than three years, especially when the electric utility industry will be competing for the same resources in order to comply with their own MACT standard. There will be a similar scarcity in equipment vendors, construction contractors, construction equipment (e.g., heavy lifting cranes), skilled labor (e.g., boilermakers), and other critical suppliers. Companies may even be unable to secure the basic building materials and control equipment (e.g., baghouses and scrubbers).

In order to retrofit a boiler, the owner will need to line up the capital necessary to pay for the retrofit. In these difficult economic times, just securing the necessary capital may take months, if not years, assuming the capital can be obtained from lending sources. In addition, the owner will need to go though the relevant permitting process(es), which will similarly take months, if not years. Finally, once the finances are secure and the permitting is complete, the owner will actually need to perform the retrofit. The design, procurement, installation, and shakedown of a retrofit project (e.g., installing a scrubber on a large boiler) can easily take more than three years. In addition, the timing of the retrofit work needs to be carefully planned, particularly for boilers that provide the primary and/or base load energy supply for their facilities. A facility owner will only shut down a boiler when everything is properly staged to ensure minimal disruption of the facility's operation. In addition to ensuring that the design work is completed and the control equipment and other supplies are on-site and ready for installation, the facility owner needs to make sure that the full suite of consultants and laborers are available for the installation. Based on a discussions with a number of potentially affected companies, the turnaround or shutdown cycles for boilers and process heaters at many of the facilities can be 1 to 5 years, making this type of precise staging exceedingly difficult to do in a three year period without substantial business interruption.

Finally, in many instances, the installation of pollution control equipment and associated charges to boiler must be permitted under state air pollution statutes and/or construction codes (building permits, etc.). The proposed rule will result in an increase in the number of permit applications, potentially swamping the state and local agencies, given the number of sources that will be making modifications as a result of the boiler and incinerator rules. Even in those areas where the rule may not result in significant increases in permitting work, the normal delays associated with permitting may make meeting the three year compliance deadline impossible.
In light of the difficulty in meeting a three year compliance deadline, EPA and authorized states should be prepared to readily grant one-year extensions under CAA § 112(i)(3)(B) to those units that have problems installing the necessary control equipment to comply with the industrial boiler MACT rule.

Response: Regarding the commenter's concerns on a reasonable implementation schedule, see response to comment EPA-HQ-OAR-2002-0058-2702.1, excerpt 218.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 264

Comment: Although the rule should not mandate fuel switching or the use of certain fuels over others, EPA should establish an extended two-step compliance period for situations where a boiler owner voluntarily elects to replace or retrofit a boiler to burn a more readily compliant fuel source. (EPA, Regulatory Impact Analysis: National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters, 3-1 (April 2010)) ("The control analysis considered fabric filters, carbon bed adsorbers, and activated carbon injection to be the primary control devices for mercury control, electrostatic precipitators for units meeting mercury limits but requiring additional control to meet the PM limits, wet scrubbers to meet the HCl limits, tune-ups, replacement burners, and combustion controls for CO and organic HAP control, and carbon injection for dioxin/furan control.") If a facility decides to switch to a different fuel, the replacement or retrofit work required to make that switch will potentially take years. Rather than require the facility to add emissions controls to its existing boiler in time for the proposed three year compliance deadline – likely eliminating the possibility that the facility would switch to a different fuel source – EPA should allow six years total for facilities to change their boilers and meet the MACT requirements for the different fuel source. This six year period would occur in two steps; a no-backsliding provision would apply for three years from publication of the rule in the Federal Register, and then the facility would have three years to comply with MACT standard for the subcategory for the cleaner fuel subcategory. EPA promulgated exactly this type of extended MACT compliance deadline for certain facilities that voluntarily elected to install new technology as part of the Pulp and Paper Cluster Rule. See Pulp and Paper Cluster Rule, 60 Fed. Reg. 18503, 18,508 (Apr. 15, 1998).(This two-step approach for the MACT standard is consistent with the D.C. Circuit's decision in NRDC v. EPA, 89 F.3d 1364 (D.C. Cir. 2007) (finding invalid EPA's decision to extend the compliance deadline for a promulgated MACT rule by a year because of the substantial changes that the agency made to the rule). Rather than functioning as an extension of the compliance deadline, this MACT standard for certain facilities would become applicable in two steps. For the first three years, a no-backsliding MACT standard would be applicable, then the three year deadline to implement the MACT standard for the applicable “cleaner” source would begin to run.) In addition to providing an incentive for facilities to switch to different fuel sources, this approach would reduce some of the competition for resources discussed above by extending the deadline to complete the work to replace or retrofit certain boilers.

Response: Regarding the commenter's concerns on a reasonable implementation schedule, see response to comment EPA-HQ-OAR-2002-0058-2702.1, excerpt 218.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 265

Comment: If EPA concludes that it cannot provide for an extended compliance period, this will not change the fact that facilities will have to install extensive emission control equipment to meet the emissions limits in the final rule. EPA itself stated in the preamble that, in order to meet the final rule, boilers would likely require a fabric filter (FF) plus carbon injection plus wet scrubber control plus combustion improvements or CO catalyst. The installation of this equipment could result in increases in emissions of CO_2 or other PSD regulated pollutants such that it is reasonable to expect that a substantial number of affected sources will need to get a PSD permit to install the controls or to otherwise take the measures that will be needed to meet the final rule. As noted above, obtaining a PSD permit is time consuming – typically anywhere from 12 to 24 months. Thus, the time needed to get a PSD permit (which must be obtained before construction actually begins) will consume one-third to two-thirds of the available compliance time under the Boiler MACT rule. The remaining time is patently insufficient for affected sources to construct and start up the needed controls. To alleviate this problem, EPA should invoke the “absurd results” or “administrative necessity” doctrines employed in the PSD GHG Tailoring Rule to provide that the MACT compliance period does not start to run until a final, non-appealable PSD permit has been issued.

Response: Regarding the commenter's concerns on a reasonable implementation schedule, see response to comment EPA-HQ-OAR-2002-0058-2702.1, excerpt 218.

Commenter Name: Ronald W. Gore
Commenter Affiliation: Alabama Department of Environmental Management
Document Control Number: EPA-HQ-OAR-2002-0058-2465.1
Comment Excerpt Number: 6

Comment: Given the stringency of many of the emission limitations listed in the proposed rule, the Department is concerned that many facilities may not have sufficient time to engineer and design the emissions control systems, raise the amount of capital to purchase the equipment, and install the required equipment. In addition, there could be hardware backlogs and/or insufficient skilled labor, which could delay compliance. The Department asks that the Agency consider a lengthy compliance timeline which would allow facilities to achieve compliance within practical timelines.

Response: Regarding the commenter's concerns on a reasonable implementation schedule, see response to comment EPA-HQ-OAR-2002-0058-2702.1, excerpt 218.

Commenter Name: Mary Graham
Commenter Affiliation: Charleston Metro Chamber of Commerce
Document Control Number: EPA-HQ-OAR-2002-0058-2732.1
Comment Excerpt Number: 13

Comment: It is apparent that, even with the changes suggested above, owners and operators will be required to retrofit countless industrial boilers and process heaters in order to meet the final rule. The proposal would set a three-year compliance deadline for existing affected sources. However, this is an exceedingly short time given the extensive nature of the needed retrofits and the limited technical resources available to accomplish the retrofits (especially in light of the fact that industrial boiler owners will be competing for equipment and technical resources with other key industry sectors such as the utility sector, which will have a similar compliance deadline for the utility MACT and also will be required to install substantial air pollution controls to meet the proposed Clean Air Transport Rule).

Response: Regarding the commenter's concerns on a reasonable implementation schedule, see response to comment EPA-HQ-OAR-2002-0058-2702.1, excerpt 218.

Commenter Name: Mary Graham
Commenter Affiliation: Charleston Metro Chamber of Commerce
Document Control Number: EPA-HQ-OAR-2002-0058-2732.1
Comment Excerpt Number: 14

Comment: Air construction permits will be required for these changes in South Carolina. The pending uncertainly and complexity of green house gas regulation under the Clean Air Act and the Tailoring Rule will be added to this process and the Chamber is concerned South Carolina Department of Health and Environmental Control and EPA will not be able to issue permits in a timely manner.

Response: Regarding the commenter's concerns on a reasonable implementation schedule, see response to comment EPA-HQ-OAR-2002-0058-2702.1, excerpt 218.

Commenter Name: Chris Greissing
Commenter Affiliation: Industrial Minerals Association
Document Control Number: EPA-HQ-OAR-2002-0058-2740.2
Comment Excerpt Number: 23

Comment: COMPLIANCE DEADLINE. The Proposed Rule 63.7495(b) establishes a compliance deadline for existing sources as three years after the date of publication of the Final Rule in the Federal Register. It will be extremely difficult, if not impossible, for all of the entities with existing boilers to make the changes necessary to comply with this rule in the three year timeframe that EPA proposes. Many boiler owners, including the soda ash companies, are likely to be unable to secure equipment, slow down operations, and obtain the necessary state permits needed to retrofit their units within three years. In light of the difficulty in meeting a three year compliance deadline, EPA should encourage states to provide one-year extensions under CAA 112(i)(3)(B) to those units that have legitimate challenges with completing the installation of the pollution control equipment required to comply with the Proposed Rule.

Even under the best of circumstances, a major retrofit of a boiler takes years from project start to finish. That process will take even more time given the range of control devices EPA anticipates will need to be installed in order to meet these new emission limits including fabric filters, carbon bed adsorbers, activated carbon injection, electrostatic precipitators, wet scrubbers, replacement burners, and combustion controls. Given that EPA has set emissions standards that no existing unit can meet, every single existing unit subject to an emission standard throughout the country will need to be retrofitted. Boiler owners will have to compete for not only the required pollution control equipment but also qualified consultants and trained contractors to assist them in designing and performing the retrofit. They also will need to secure the necessary permits and find an appropriate time for the work to be done. The timing of a boiler shutdown is especially critical to the soda ash industry which, because of its location in remote southwest Wyoming, rely on multiple boilers as the primary energy supply for facility operations. It is simply unrealistic for EPA to conclude that sources will be able to meet the three year compliance deadline.

Response: Regarding the commenter's concerns on a reasonable implementation schedule, see response to comment EPA-HQ-OAR-2002-0058-2702.1, excerpt 218.

Commenter Name: William R. Ermatinger
Commenter Affiliation: Northrop Grumman
Document Control Number: EPA-HQ-OAR-2002-0058-2506.1
Comment Excerpt Number: 23

Comment: NGSB has determined that proposed limits would require construction of a new powerhouse. Even if NGSB were to begin design of a new, replacement powerhouse now — before the new regulation is finalized — the project would not be completed before 2015 under typical timelines for such a major project. New air permitting requirements, including PSD for greenhouse gases, could add two years to the schedule — two years during which no large equipment may be ordered and no construction completed. A crush of orders from the regulated community for new boilers and emissions control equipment resulting from the proposed regulation is expected to lead to abnormally long lead times. Furthermore, NGSB's three main powerhouse boilers could not all be shut down and replaced at one time; the units would need to be replaced sequentially, with sufficient time allowed between replacements to ensure reliable operation of each new boiler. Assuming the proposed rule is finalized in December 2010, it could be 72 months or more before new boilers could be in place at NGSB, commissioned, and made operational at a level to support facility operations.

Response: Regarding the commenter's concerns on a reasonable implementation schedule, see response to comment EPA-HQ-OAR-2002-0058-2702.1, excerpt 218.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 31

Comment: Proposed 63.7495(b) states If you have an existing boiler or process heater, you must comply with this subpart no later than [3 YEARS AFTER DATE THE FINAL RULE IS PUBLISHED IN THE FEDERAL REGISTER]. However, this is a major rulemaking [Footnote: As EPA states on page 32044 of the preamble, an initial screening analysis for impact on small entities indicated a likely significant impact for substantial numbers ...] and the Agency must provide 60 days for Congressional review. Thus, the effective date of the rule must be set at least 60 days after publication in the Federal Register and the compliance date should be 3 years after the effective date.

Recommendation: Provide time for Congressional Review of the final rule as required by the Congressional Review Act.

Response: We have modified the final rule language to incorporate the 60 day after publication of the rule as the effective date of the rule. We have still begun the three year compliance date for existing sources as three years after publication of the final rule in the federal register. The Congressional Review Act only specifies the effective date of the rule but it does not specify the compliance date of the rule as long as that date occurs after the effective date.

Commenter Name: Matthew Todd and David Friedman

Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 32

Comment: It is apparent that, even with the changes suggested in these comments, owners and operators will be required to retrofit countless industrial boilers and process heaters with extensive controls in order to meet the emission limits in the final rule. The proposal would set a three-year compliance deadline for existing affected sources and even less compliance time for boilers and process heaters that began construction or reconstruction after the proposal date. Three years is an exceedingly short time given the extensive nature of the needed retrofits and the limited technical and supply resources available to supply the required controls and monitors and accomplish the retrofits, especially in light of the fact that industrial boiler and process heater owners will be competing for equipment and technical resources with area sources, CISWI sources and other key industry sectors such as the utility sector, which will have a similar compliance deadline for the utility MACT.

While this is not an issue for most refineries if the proposal not to impose emission limitations for Gas 1 units is finalized, it is a significant problem for non-refining major sources owned or operated by our member companies and a particular concern for refineries where liquid fuels must be used. For Gas 2 major sources and for individual refineries with significant liquid-firing, such as those without access to natural gas, installing multiple control technologies on tens of liquid-fired boilers and process heaters is simply not technically or economically feasible in three years. It is simply not possible to design, procure and install control equipment of this magnitude in three years, while a huge number of others are doing the same. Moreover, the installation of these controls requires shutdown of the process units that the boilers and process units service. Most such work is typically coordinated during major process unit turnarounds so that the economic penalty of an extra, enforced shutdown is not imposed. Five and six year turnaround schedules are typical for refineries. Thus, a three year compliance time would force many early shutdowns, incurring major production penalties and generating excess emissions and excess wastes, even assuming the additional facilities could be engineered and constructed in such a short time.

The shutdown penalty is a particular burden for remote, liquid-firing facilities. The reason natural gas is not available to these sources is the remoteness of their locations (e.g., Alaska, Hawaii, and Virgin Islands). Because they are remote, there are exceptional logistical difficulties beyond those typically encountered in the Continental U.S. and it is simply not possible to design, procure and install control equipment of this magnitude in three years.
To address this problem, EPA must adopt a significantly longer initial compliance deadline for both new and existing boilers and process heaters. Nominally, EPA should adopt by rule an across-the-board one-year extension pursuant to CAA section 112(i)(3)(B) for any unit subject to an emission limit under this regulation. However, even a four-year compliance period will be inadequate for many affected sources. Therefore, EPA should provide additional time by: (1) granting in the final rule a Presidential extension under CAA section 112(i)(4), given that it is in the national security interests of the United States to prevent widespread noncompliance in the industrial base; (2) declaring that the statutory three-year compliance period is impossible to

meet or otherwise produces absurd results, which as demonstrated in EPA's recent PSD Tailoring Rule are doctrines that allow EPA to depart from statutory directives in appropriate circumstances; and/or (3) establishing phased or sequenced requirements such that some elements of the rule become effective no later than three years after promulgation (thus satisfying CAA section 112(i)(3)(A)), while others are phased in at later times.

Recommendation: Provide up to five years for any unit subject to emission limits to comply with this rule.

Response: Regarding the commenter's concerns on a reasonable implementation schedule, see response to comment EPA-HQ-OAR-2002-0058-2702.1, excerpt 218.

Commenter Name: David A. Buff
Commenter Affiliation: Golder Associates Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2801.1
Comment Excerpt Number: 79

Comment: Due to the complexity of this rule (multiple pollutant emission limits), it is requested that an automatic extension of 1 year be afforded in the rules, beyond the standard 3-year compliance schedule. This will allow sources with multiple boilers additional needed time to investigate availability of resources and equipment, and to spread capital and operating costs associated with complying with the rule. This is similar to what has been afforded to the pulp and paper industry MACT I, Phase 2 extended compliance time.

Boilers that installed controls for first Industrial Boiler MACT rule, or those that built new boilers to comply with the first MACT rule, should be allowed extensions to avoid having to spend capital again so soon.

Response: Regarding the commenter's concerns on a reasonable implementation schedule, see response to comment EPA-HQ-OAR-2002-0058-2702.1, excerpt 218.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-2702.1
Comment Excerpt Number: 129

Comment: Availability of CO CEMS.
It appears that over 1000 CO CEMS might be required under this rule. This is a very high number that will be required over a short time period. EPA has provided no information or assurance that that number of units can be provided by suppliers. EPA should investigate this issue and allow for an extended compliance date if availability of CO CEMS is a problem.

Response: CO CEMS is no longer a requirement in the final rule. Regarding the commenter's concerns on a reasonable implementation schedule, see response to comment EPA-HQ-OAR-2002-0058-2702.1, excerpt 218.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-2702.1
Comment Excerpt Number: 151

Comment: Compliance Timeline
Compliance Deadline for Existing Sources.
EPA proposes to set the compliance deadline for existing affected sources at three years after the date of publication of the final rule in the Federal Register. 75 FR 32035. This provides an inadequate amount of time for the thousands of affected sources to be retrofitted as necessary to meet the new MACT standards. EPA estimates that 3,730 existing units will have to come into compliance with the proposed MACT standards. This is an unprecedented number of sources impacted by a MACT ruling. These units are all solid fuel-fired, i.e., predominantly coal-fired, units. In order to meet the MACT standards, owners will, by and large, have to install add-on controls.

We anticipate that industry will face severe time and material constraints that will make it extremely difficult, if not impossible, for many facilities to meet the retrofit deadline of three years. Most of the targeted solid fuel- fired units are located at facilities that will have to undergo substantial re-engineering, e.g., due to space constraints, to accommodate new controls. Design, procurement, installation, and shakedown of these projects will easily consume three years. In short, more time is needed. External factors will also jeopardize compliance within three years. A large number of companies will be competing nationwide for limited resources and materials from engineering consultants, equipment vendors, construction contractors, financial institutions, and other critical suppliers. This competition for limited resources will be compounded by the promulgation of the Clean Air Transport Rule, the Utility MACT, Regional Haze SIP's and/or FIP's at roughly the same period of time, which will introduce competition from electric utilities in addition to competition from other industrial boiler owners. Much of the pollution control equipment may not even be available within EPA's proposed compliance timeframe. By extending the compliance time, EPA would allow for the development of new creative technology to provide superior emissions control

It is likely many companies will find themselves unable to procure the necessary goods and services to complete the retrofitting of their affected units within three years. In particular, we anticipate problems procuring baghouses and scrubbers because immediate industry demand will outstrip immediately available supplies. For example, in preparation for compliance with the prio MACT, a scrubber project at one of CIBO's member facilities took four years to implement. Industry must continue to operate as best as possible while retrofitting to meet the new MACT standards. Construction on units will need to be staggered as facilities with multiple units will require equipment to be installed with units out of service. Staggering work on separate units a the same facility allows continued operation; however, this staggering extends the overall compliance time.

In general, the existing solid fuel-fired boilers that will be subject to this new rule comprise the most critical part of the base load energy supply for their facilities. These units typically have high capacity utilization rates. Extensive outages for retrofitting must be carefully planned. Only when all of the critical prerequisites for the retrofit have been lined up, e.g., the engineering is complete and the control equipment is staged for immediate installation, can an owner afford to shut down a facility's base load boiler to install the new controls. This takes planning and coordination both within the company and contractors.

Many units must conduct emissions testing prior to retrofitting units in order to determine the best means of achieving compliance. There are a limited number of emission testing contractors and laboratories capable of conducting this type of testing, which will further the delay. Where testing determines that emission limitations are unachievable and retrofitting is infeasible, it is possible they will decide to re-power or switch fuels. These additional processes would surely extend beyond the three year compliance timeframe proposed by EPA. Even under the best case scenario, undertaking a retrofit can take five years. Three years is simply not sufficient to allow owners of many of the affected sources the time necessary to make the retrofits without substantial disruption to the operation of their facilities.

The process to undertake a retrofitting project is more complex then EPA appreciates. Regulated sources need time to obtain capital funding. Some facilities will have to obtain capital funding for these projects thru a formal request process that by itself could last two years. Those facilities reliant upon the state funding process can only seek legislative approval when the rule is final.

Response: Regarding the commenter's concerns on a reasonable implementation schedule, see response to comment EPA-HQ-OAR-2002-0058-2702.1, excerpt 218.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-2702.1
Comment Excerpt Number: 153

Comment: We recommend EPA address the foregoing problems by extending the compliance deadline to four years after the publication of the final regulations in the Federal Register. We believe the Agency would be fully justified in invoking § 112(i)(3)(B) to grant owners of all affected sources a one-year extension of the compliance deadline. Four years would provide critically needed time for industry to conduct the necessary retrofitting with controls and absorb the great cost of these retrofits. Given the magnitude of the retrofit requirements and the likelihood of substantial difficulties fulfilling these requirements, it is essential that EPA provide whatever relief may be possible.

There is established precedent for allowing sources more time to comply. Specifically, the final NESHAP for the Pulp and Paper Production source category includes an eight year compliance deadline. 63 FR 18519. Additionally, EPA extended the compliance date for the miscellaneous organics chemical manufacturing (MON) MACT. That standard was challenged in court with EPA and industry agreeing to a settlement. As part of the settlement, EPA extended the compliance deadline.

Response: Regarding the commenter's concerns on a reasonable implementation schedule, see response to comment EPA-HQ-OAR-2002-0058-2702.1, excerpt 218.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 163

Comment: 63.7505(g) specifies that for a new or reconstructed source that commenced construction or reconstruction between [INSERT DATE OF PUBLICATION OF THIS PROPOSED RULE IN THE FEDERAL REGISTER], and [DATE 60 DAYS AFTER PUBLICATION OF THE FINAL RULE IN THE FEDERAL REGISTER], and you chose to comply with the proposed emission limits when demonstrating initial compliance, you must conduct a second compliance demonstration for the promulgated emission limits within 3 years after [DATE 60 DAYS AFTER PUBLICATION OF THE FINAL RULE IN THE FEDERAL REGISTER] or within 3 years after startup of the affected source, whichever is later. However, per 63.6(b)(3) a source in this situation has three years from the effective date of the final rule to comply with the emission limitation in the final rule. Requiring the performance test before the three year compliance period is up significantly shortens the compliance period provided by the part 63 General Provisions and contravenes the normal requirement that the performance test be done within 180 days after achieving compliance.

Recommendation: Proposed 63.7505(g) should be revised to require the performance test within 180 days after the boiler or process heater complies with the final standard and no later than 3 years and 180 days after the effective date of the final rule.

Response: We have revised 63.7510 to address situations for new or reconstructed sources that commenced construction or reconstruction between proposal and promulgation of the final rule in order to be consistent with the general provisions 63.6(b)(3). We have also added a new Table 12 to the final rule to discuss the limits applicable to these new sources. Section 63.6(b)(3) only allows to three years after the effective date of the final standard if the owner or operator complies with the proposed standard during the 3-year period immediately after the effective date. In order demonstrate compliance with the proposed standard a unit must conduct its initial performance test on the same schedule as other new or reconstructed sources.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-2702.1
Comment Excerpt Number: 209

Comment: Demonstrating compliance on monthly basis for first 12 months is unworkable Compliance on a monthly basis during the first twelve months of compliance period is unworkable. Proposed 63.7522(f)(3) requires a facility to generate enough credits to offset the debits each and every calendar month up until 12 months are accumulated and, thereafter, determine compliance on a twelve month rolling average basis. This requirement unnecessarily restricts the utility of the emission averaging provision. For example, in the case where a facility over-controls one boiler while under-controlling the other, there will be months when the facility could not comply. This would certainly be true during a month when the credit-generating unit is down for its periodic maintenance outage. Due to the necessary length of these outages (4-6 weeks), there could conceivably be two or three months in a row where the facility could not comply with proposed averaging provisions. There will be other cases where the credit-generating unit experiences an unanticipated outage and the debit-generating unit is required to operate more to compensate.

For these reasons, this provision should be eliminated. CIBO notes that the HON, which EPA references, includes an annual emission test along with a quarterly emission test where the average emissions must be less than 130 percent of the allowable emissions. Here, EPA acknowledges that a short term average (quarterly) must provide some tolerance as compared to an annual average. CIBO brings this point up, not to suggest to EPA to adopt the HON quarterly test, but to illustrate that EPA emissions averaging provisions have accounted for this issue. Also, CIBO would note that the HON is written for an entirely different industry than the case of boilers and process heaters. Due to the circumstances described above (extended outages while other units take on additional load), a facility using emissions averaging for boilers and process heaters should be subject to only annual compliance determinations.

Response: See response to EPA-HQ-OAR-2002-0058-2824.1, excerpt 32 for response to comment on timing of first compliance demonstration.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-2702.1
Comment Excerpt Number: 218

Comment: Another complicating issue is that EPA has not provided guidance on what is required for BACT for CO2e. A tremendous amount of time and effort has gone into BACT determinations for criteria pollutants over last decade and an equal or larger effort will be required for BACT determinations for CO2e.

The timeline for compliance with Boiler MACT is to install emission control equipment by 2013. Permitting work for installation will be required two or more years prior to 2013, meaning that the PSD tailoring rule will apply to larger facilities within this time frame. Therefore, these larger facilities will have to evaluate whether or not the project to comply with Boiler MACT triggers PSD. In addition, smaller facilities may have to perform this evaluation out of an abundance of caution because there is no guarantee that the higher tailoring rule applicability threshold will be accepted due to the pending evaluation that states are making as to whether or not their laws with statutory thresholds of 100/250 ton per year can be changed. Further, pending legal challenges may result in statutory thresholds as well. Facilities that trigger PSD and their state regulators will be faced with BACT determinations for CO2e and in all likely-hood will have little-to-no guidance from EPA by then. Many states make no decisions about PSD without EPA guidance because they fear that EPA will not agree with their determinations or that some non-government organization will file a legal challenge. The result will be catastrophic because no decisions will be made and the facility will have no certainty for the capital required.

The theme of uncertainty is of critical importance because the long-term viability of a facility and its associated jobs is dependent on capital spending to ensure its continued competitiveness. Other developing countries have none of these rules thereby making investment (e.g. moving a U.S. facility's production to another country) financially attractive and there is far less uncertainty.

Response: The EPA disagrees with the commenters that the 3-year compliance deadline is too short considering the number of sources that will be competing for the resources and materials from engineering consultants, permitting authorities, equipment vendors, construction contractors, financial institutions, and other critical suppliers. We know that many sources subject to the standard are gas fired units or small boilers (less than 10 mmBtu/hr) and will not need to install controls in order to demonstrate compliance with the standard. As a result, since not everyone will need more than 3 years to actually install controls, the final rule does not allow an extra year for existing sources to comply with the final rule. Section 112(i)(3)(B) allows EPA, on a case-by-case basis to grant an extension permitting an existing source up to one additional year to comply with standards if such additional period is necessary for the installation of controls. The EPA feels that this provision is sufficient for those sources where the 3-year deadline would not provide adequate time to retrofit as necessary to comply with the requirements of the standard. EPA appreciates the other ongoing regulatory burden and uncertainty placed on industry and permitting authorities to address PSD and BACT issues with respect to greenhouse gas emissions. However, the three-year compliance deadline is a statutory requirement of Section 112.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-2702.1
Comment Excerpt Number: 219

Comment: In order to remove some of this uncertainty, the EPA should categorically exempt projects required to comply with Boiler MACT from additional regulatory burdens such PSD. Alternatively, EPA should establish that the deadline for compliance with this rule be three years following the issuance of the required construction permits by a site's permitting authority. This would provide relief to the boiler owner in the event that the permitting authority is unable to issue the required permits in a timely fashion, whether due to uncertainty of BACT for CO2e determinations, or due to a backlog of permit applications that are anticipated due to the Tailoring Rule.

Response:
Three years after the effective date of the MACT standard is the maximum amount of time that the Clean Air Act provides for a source to come into compliance (see CAA Section 112(i)(3)(A)), and the Agency has provided that maximum amount of time. In accordance with CAA Section 112(i)(3)(B), EPA or a State with a program approved under title V of the Clean Air Act may issue a permit that grants up to one additional year to comply, if such time is necessary for the installation of controls.

Commenter Name: Robert Bauer
Commenter Affiliation: Kentucky Forest Industries Association
Document Control Number: EPA-HQ-OAR-2002-0058-3186.1
Comment Excerpt Number: 3

Comment: Sufficient compliance timelines
Given the stringency of many of the emissions limitations listed in the proposed rule, the Association is concerned that many facilities may not have sufficient time to engineer and design the emissions control systems, raise the amount of capital to purchase the equipment, and install the required equipment. In addition, there could be hardware backlogs and/or insufficient skilled labor, which could delay compliance. The Association asks that the Agency consider a lengthily compliance timeline which would allow facilities to achieve compliance within practical timelines.

Response: Three years after the effective date of the standard is the maximum amount of time that the Clean Air Act provides for a source to come into compliance (see CAA Section 112(i)(3)(A)), and the Agency has provided that maximum amount of time. In accordance with CAA Section 112(i)(3)(B), EPA or a State with a program approved under title V of the Clean Air Act may issue a permit that grants up to one additional year to comply, if such time is necessary for the installation of controls.

Commenter Name: Ken Wiegand
Commenter Affiliation: Denison University
Document Control Number: EPA-HQ-OAR-2002-0058-2834.1

Comment Excerpt Number: 3

Comment: EPA should provide regulatory relief for the regulated community that has provided certification and documentation under 112 (J) filings with individual authorized state agencies to comply with the remanded Boiler MACT. EPA at a minimum, should give consideration to this regulated group with an extended compliance deadline recognizing the expenditures and continuing efforts made during the interim limbo status of the Boiler MACT. A three year extension beyond the proposed three year compliance deadline is suggested. The cost of

compliance testing, work practice controls, control technology changes and monitoring system installations to meet the proposed Industrial Boiler MACT standards are excessively high for the degree of emission reductions proposed. Averaging these costs over a period of time, may give some regulatory relief to this regulated group of boilers that has strived to achieve recognizable progress towards compliance with the remanded MACT.

Response: Regarding the commenter's concerns on a reasonable implementation schedule, see response to comment EPA-HQ-OAR-2002-0058-2702.1, excerpt 218.

Commenter Name: Chelly Reesman
Commenter Affiliation: JR Simplot Company
Document Control Number: EPA-HQ-OAR-2002-0058-3162
Comment Excerpt Number: 3

Comment: Compliance Dates
Within 3 years after the implementation of the proposed regulation, an affected source must achieve compliance with the applicable provisions in the rule.
It is anticipated that compliance will require installation of additional control equipment which in turn requires, capital equipment budgeting, design, selection, manufacturing time for the control equipment, and possibly air permitting. It is unclear that it is possible to achieve compliance within 3 years. In particular, obtaining any necessary air permits in a timely matter has been an ongoing issue in a number of areas where Simplot does business in the United States.

Response: Regarding the commenter's concerns on a reasonable implementation schedule, see response to comment EPA-HQ-OAR-2002-0058-2702.1, excerpt 218.

Commenter Name: Jeffrey R.Klieve
Commenter Affiliation: Monsanto Company
Document Control Number: EPA-HQ-OAR-2002-0058-2754.1
Comment Excerpt Number: 4

Comment: Proposed Compliance Timeframe (75 Fed. Reg. 32050)

Monsanto is concerned with the proposed timeframe for compliance with the MACT standards for existing affected units. The current rule, as written, will affect thousands of major sources and an equal or greater number of area sources -all with the same compliance time frame. The demand on vendors of air pollution control equipment and continuous emission monitoring systems, as well as service firms such as consultants and stack testing firms, will vastly exceed current nation-wide capabilities. This demand on resources could also be exacerbated by pending regulations aimed at reducing air emissions from the electric utility generating sector.

If additional air pollution control equipment is required to meet the final emission limitations, Monsanto requests that USEP A consider a compliance time frame of 5 years or more to allow for proper planning, design, procurement, installation and final startup of the air pollution control and related equipment.

Response: Regarding the commenter's concerns on a reasonable implementation schedule, see response to comment EPA-HQ-OAR-2002-0058-2702.1, excerpt 218.

Commenter Name: H. Allen Faulkner
Commenter Affiliation: Ascend Performance Materials, LLC
Document Control Number: EPA-HQ-OAR-2002-0058-2743.1
Comment Excerpt Number: 5

Comment: Ascend requests the EPA to reconsider the 3-year compliance date for this rule. Currently, there is no proven control technology identified to reduce Dioxin/Furan emissions from coal fired boilers. While equipment vendors have stated that control equipment could have a 2 year lead time, they are also reluctant to guarantee control equipment specifications to the emission levels identified in the rule for all pollutants. These factors make it extremely difficult for companies to engineer and order the appropriate control equipment within the required 3-year compliance period.

These new limits are neither demonstrated nor accurately measurable and that is a source of tremendous concern for us. We have worked diligently over the years to maintain compliance of our assets through imaginative and diligent application of proven scientific principles. Since there are no proven technologies to measure or achieve all limits on a single boiler, we ask the Agency to consider a longer compliance period, perhaps 5 years, to allow industry to develop and validate the systems and supply chains that are necessary to meet this new challenge.

Response: See the preamble for discussion of dioxin/furan work practice standards. Regarding the commenter's concerns on a reasonable implementation schedule, see response to comment EPA-HQ-OAR-2002-0058-2702.1, excerpt 218.

Commenter Name: Frank Kohlasch
Commenter Affiliation: Minnesota Pollution Control Agency

Document Control Number: EPA-HQ-OAR-2002-0058-2773.1
Comment Excerpt Number: 5

Comment: Provide as much time as the law allows for compliance. The MPCA recognizes that for some boiler or process units, substantial air pollution control upgrades are needed to comply with the proposed rules. Given the number of affected units and the simultaneous need for engineering, construction, finance and other technical services throughout many different industrial sectors, EPA should allow as much time as possible for facilities to achieve compliance. Section 112(i)((3)(b) allows the Administrator or a state with an approved Title V program) to provide a one year extension of the compliance deadline if the extension is deemed necessary to install controls. It would be valuable to states if EPA would include in the final rule the required evidence of affected source would submit to support granting an extension. A deadline for submitting a request would be valuable in aiding states' ability to process requests in a timely manner.

Response: Regarding the commenter's concerns on a reasonable implementation schedule, see response to comment EPA-HQ-OAR-2002-0058-2702.1, excerpt 218.

Commenter Name: Jacquelyn Taylor
Commenter Affiliation: South Carolina Pulp and Paper Association
Document Control Number: EPA-HQ-OAR-2002-0058-3154.1
Comment Excerpt Number: 7

Comment: Air construction permits will be required for these changes in South Carolina. The pending uncertainly and complexity of green house gas regulation under the Clean Air Act and the Tailoring Rule will be added to this process and SCPPA is concerned South

Carolina Department of Health and Environmental Control and EPA will not be able to issue permits in a timely manner.

Response: Regarding the commenter's concerns on a reasonable implementation schedule, see response to comment EPA-HQ-OAR-2002-0058-2702.1, excerpt 218.

Commenter Name: Eric Trauner
Commenter Affiliation: Citizen
Document Control Number: EPA-HQ-OAR-2002-0058-2768
Comment Excerpt Number: 7

Comment: The date for compliance should be set at five years, not three. By definition, there will be facilities that will not be able to comply with this MACT. Intelligent consideration of compliance options in such cases has many steps, each taking several months. For instance, it will take several weeks for a facility to review the final MACT and develop a compliance plan.

A likely first step in such a compliance plan would be evaluation of current status, likely by stack testing. Because there are in fact a limited number of stack testers genuinely qualified to execute such work, even this seemingly simple step of compliance determination will take several months (as US-EPA has recently learned). Then, a review of compliance options in terms of engineering and economics will also take several months to a year. Hard engineering design can take an additional year or longer, followed by what could well be two years for acquisition of equipment, installation, and start-up/ shakedown, with a final official stack test. A sound compliance effort cannot be completed in three years.

Response: Regarding the commenter's concerns on a reasonable implementation schedule, see response to comment EPA-HQ-OAR-2002-0058-2702.1, excerpt 218.

Commenter Name: Dennis A. Werblow
Commenter Affiliation: Decorative Panels International, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2599.1
Comment Excerpt Number: 9

Comment: As mentioned above, DPI invested $4.5 million into ESP control equipment in 2008 to comply with the original MACT standards. The lower emission limits of the new MACT proposal would require another substantial investment into control technology - if a financially viable solution to the new standards were identified. It is reasonable to allow companies like us, which made these previous investments, to have additional time to comply with the newer and lower limits.

Response: Regarding the commenter's concerns on a reasonable implementation schedule, see response to comment EPA-HQ-OAR-2002-0058-2702.1, excerpt 218.

Commenter Name: Thomas Bakk
Commenter Affiliation: State of Minnesota Senate
Document Control Number: EPA-HQ-OAR-2002-0058-2950
Comment Excerpt Number: 13

Comment: The three year compliance deadline must be extended for existing sources. It is unreasonable to expect that all of the sources that must retrofit can accomplish the necessary testing, systems design and engineering and equipment production when thousands of facilities are seeking these services. Section 112(i)(4) provides the legal basis for an extended compliance period.

Response: Regarding the commenter's concerns on a reasonable implementation schedule, see response to comment EPA-HQ-OAR-2002-0058-2702.1, excerpt 218.

Commenter Name: Christy Sammon
Commenter Affiliation: Southeast Lumber Manufacturers Association
Document Control Number: EPA-HQ-OAR-2002-0058-2727.1
Comment Excerpt Number: 24

Comment: Given the tens of thousands of boilers that will have to be controlled as a result of these rules, it is unlikely that the capacity of existing vendors, contractors, engineers, and state regulatory personnel is sufficient to allow completion of all of the required modifications in a 3-year time period, or even a 4-year time period if facilities were granted a 1-year extension. EPA should evaluate all of the necessary capabilities and establish a compliance period based upon that evaluation.

Response: Regarding the commenter's concerns on a reasonable implementation schedule, see response to comment EPA-HQ-OAR-2002-0058-2702.1, excerpt 218.

Commenter Name: J. Michael Geers
Commenter Affiliation: Duke Energy
Document Control Number: EPA-HQ-OAR-2002-0058-2765.1
Comment Excerpt Number: 25

Comment: Compliance Time
EPA proposes to set the compliance deadline for existing affected sources at three years after the date of publication of the final rule in the Federal Register. Duke Energy believes this provides an inadequate amount of time for the thousands of affected sources to be retrofit as necessary to meet the new MACT standards. When finalized, EPA estimates that under the

alternative solid waste definition, the MACT standards will apply to the existing fleet of 525 coal units, 239 biomass units, 791 liquid fired units and 11,524 gas fired units. The capital costs will fall predominately to those industries which have solid fuel-fired, i.e., predominantly coal-fired, and bio-mass units. In order to meet the MACT standards, these owners will, by and large, have to install add-on controls. According to Table 9, out of a total of 13,079 existing units that will require controls, 764 are solid fuel fired, or about 6% of the total. The solid fuel fired units will require a capital investment of $5.1 billion out of the total $8.0 projected capital cost. While not discussed in detail in these comments, Duke Energy believes that EPA has significantly underestimated the capital cost of compliance with these rules. What is equally puzzling is that EPA projects in Table 11 that the rules will apply to only 46 new units. Duke Energy believes that this number is grossly understated since many solid fuel fired units may be forced by economics to shutdown and repower with new boilers fired by natural gas or other fuels. More egregiously, many of these sources will alternatively decide to shut down permanently.

Response: The EPA disagrees with the commenters that the 3-year compliance deadline is too short considering the number of sources that will be competing for the resources and materials from engineering consultants, permitting authorities, equipment vendors, construction contractors, financial institutions, and other critical suppliers. We know that many sources subject to the standard are gas fired units or small boilers (less than 10 mmBtu/hr) and will not need to install controls in order to demonstrate compliance with the standard. As a result, since not everyone will need more than 3 years to actually install controls, the final rule does not allow an extra year for existing sources to comply with the final rule. The commenter incorrectly notes that 13, 079 existing units will require controls, many of these units are gas-fired units, limited use units, or small units that will demonstrate compliance with a work practice standard. Further, EPA has consolidated the proposed subcategories for biomass and coal into a single solid fuel subcategory for fuel based HAP in order to address concerns with multifuel units. This consolidation is also expected to reduce the number of units requiring add-on controls for HCl emission limits. See the response to comments made in the new unit projection section for the estimated number of new solid fuel boilers. Section 112(i)(3)(B) allows EPA, on a case-by-case basis to grant an extension permitting an existing source up to one additional year to comply with standards if such additional period is necessary for the installation of controls. The EPA feels that this provision is sufficient for those sources where the 3-year deadline would not provide adequate time to retrofit as necessary to comply with the requirements of the standard.

Commenter Name: J. Michael Geers
Commenter Affiliation: Duke Energy
Document Control Number: EPA-HQ-OAR-2002-0058-2765.1
Comment Excerpt Number: 26

Comment: Duke Energy anticipates that industry will face severe time and material constraints that will make it extremely difficult, if not impossible, for many facilities to meet the retrofit deadline of three years. Most of the targeted solid fuel-fired units are located at facilities that will have to undergo substantial re-engineering, e.g., due to space constraints, to accommodate new controls. Design, procurement, installation, and shakedown of these projects will easily consume three years. In short, more time is needed. Moreover it is inevitable that many existing boilers will be forced to convert to an alternative fuel such as natural gas, or even construct entirely new boilers. According to its rulemaking to date, EPA has not adequately considered these factors.

Response: Regarding the commenter's concerns on a reasonable implementation schedule, see response to comment EPA-HQ-OAR-2002-0058-2702.1, excerpt 218.

Commenter Name: J. Michael Geers
Commenter Affiliation: Duke Energy
Document Control Number: EPA-HQ-OAR-2002-0058-2765.1
Comment Excerpt Number: 27

Comment: External factors will also jeopardize compliance within three years. A large number of companies will be competing nationwide for limited resources and materials from engineering consultants, equipment vendors, construction contractors, financial institutions, and other critical suppliers. It is likely many companies will find themselves unable to procure the necessary goods and services to complete the retrofitting of their affected units within three years. In particular, Duke Energy is concerned about sources being able to procure bag houses and scrubbers because immediate industry demand will outstrip immediately available supplies.

Response: Regarding the commenter's concerns on a reasonable implementation schedule, see response to comment EPA-HQ-OAR-2002-0058-2702.1, excerpt 218.

Commenter Name: J. Michael Geers
Commenter Affiliation: Duke Energy
Document Control Number: EPA-HQ-OAR-2002-0058-2765.1
Comment Excerpt Number: 28

Comment: EPA must also realize that these retrofits will not occur in a vacuum. Because of EPA's recently proposed Transport Rule and the forthcoming Utility MACT Rule, a large amount of

retrofits will occur at the same time sources are attempting to meet the requirements of the Industrial Boiler MACT. Since many industrial boilers and process heaters can be relatively small sources, it is plausible that they will suffer from lower priorities compared to larger utility boilers.
Industry must continue to operate as best as possible while retrofitting to meet the new MACT standards. In general, the existing solid fuel-fired boilers that will be subject to this new rule comprise the most critical part of the base load energy supply for their facilities. These units typically have high capacity utilization rates. Extensive outages for retrofitting must be carefully planned. Only when all of the critical prerequisites for the retrofit have been lined up, e.g., the engineering is complete and the control equipment is staged for immediate installation, can an owner afford to shut down a facility's base load boiler to install the new controls. This will take careful planning and coordination both within the company and outside the company that will involve with engineering consultants, equipment vendors, and construction contractors. Duke Energy does not believe three years is sufficient to allow owners of many of the affected sources the time necessary to make the retrofits without substantial disruption to the operation of their facilities.

Response: Three years after the effective date of the standard is the maximum amount of time that the Clean Air Act provides for a source to come into compliance (see CAA Section 112(i)(3)(A)), and the Agency has provided that maximum amount of time. In accordance with CAA Section 112(i)(3)(B), EPA or a State with a program approved under title V of the Clean Air Act may issue a permit that grants up to one additional year to comply, if such time is necessary for the installation of controls.

Commenter Name: John Hopewell

Commenter Affiliation: American Coatings Association
Document Control Number: EPA-HQ-OAR-2002-0058-2886.1
Comment Excerpt Number: 29

Comment: EPA should allow a longer compliance timeframe .

Response: Regarding the commenter's concerns on a reasonable implementation schedule, see response to comment EPA-HQ-OAR-2002-0058-2702.1, excerpt 218.

Commenter Name: J. Michael Geers
Commenter Affiliation: Duke Energy
Document Control Number: EPA-HQ-OAR-2002-0058-2765.1
Comment Excerpt Number: 30

Comment: Duke Energy recommends EPA extend the compliance deadline to four years after the publication of the final regulations in the Federal Register. Duke Energy believes that the Agency would be fully justified in invoking 112(i)(3)(B) of the Clean Air Act to grant owners of all affected sources a one year extension of the compliance deadline. Four years would provide critically needed time for industry to conduct the necessary retrofitting with controls and absorb the great cost of these retrofits. Given the magnitude of the retrofit requirements and the likelihood of substantial difficulties fulfilling these requirements, it is essential that EPA provide all the flexibility within their authority. The one year compliance extension authorized by the Act is a legitimate and necessary solution to this problem, and Duke Energy urges EPA to incorporate a general one year compliance extension for existing affected sources in the final BPH MACT rule. In addition EPA must clearly articulate the conditions under which a source is eligible for this extension at the time that the rule is finalized. If it is uncertain that a source can qualify for an extension or it must go through an uncertain regulatory approval process, there is no way a source can effectively factor that extension into its planning process and risk possible noncompliance. Duke Energy supports giving this extension to all sources that actually install controls to attain compliance.

Response: Regarding the commenter's concerns on a reasonable implementation schedule, see response to comment EPA-HQ-OAR-2002-0058-2702.1, excerpt 218.

Commenter Name: David Bonistall
Commenter Affiliation: NewPage Corp
Document Control Number: EPA-HQ-OAR-2002-0058-2920.1
Comment Excerpt Number: 33

Comment: The timeline for compliance with Boiler MACT will most likely require installation of emission control equipment by 2013. Permitting work for installation will be required two or more years prior to 2013, meaning that the PSD tailoring rule will apply to larger facilities within this time frame. Therefore, these facilities will have to evaluate whether or not the project to comply with Boiler MACT triggers PSD. In addition, due to the pending evaluation that states are making as to whether or not their laws with the statutory thresholds of 100/250 ton per year can be changed. Further, pending legal challenges may result in statutory thresholds as well. Facilities that trigger PSD and their state regulators will be faced with BACT determinations for GHGs and in all likelihood will have little-to-no guidance from EPA. Many states make no decisions about PSD without EPA guidance because they fear that EPA will not agree with their determinations or that some non-government organization will file a legal challenge. The result will be catastrophic because no decisions will be made and the facility will have no certainty for the capital required. In addition, with the uncertainty surrounding GHG BACT, facilities will also not have certainty for the timeline for obtaining the permits needed to make the changes required for Boiler MACT compliance. The PSD permitting process is notorious for having a long timeline and since construction cannot begin until all penult approvals are obtained, any further delays in the PSD process could jeopardize a facility meeting the compliance dates.

Response: Regarding the commenter's concerns on a reasonable implementation schedule, see response to comment EPA-HQ-OAR-2002-0058-2702.1, excerpt 218.

Commenter Name: David Bonistall
Commenter Affiliation: NewPage Corp
Document Control Number: EPA-HQ-OAR-2002-0058-2920.1
Comment Excerpt Number: 34

Comment: Even with the changes suggested in our comments, owners and operators will be required to retrofit a significant number of industrial boilers in order to meet the final rule. The proposal would set a three-year compliance deadline for existing affected sources. However, this is an exceedingly short time given the extensive nature of the needed retrofits and the limited technical resources available to accomplish the retrofits (especially in light of the fact that industrial boiler owners will be competing for equipment and technical resources with other key industry sectors such as the utility sector, which will have a similar compliance deadline for the utility MACT and also will be required to install substantial air pollution controls to meet the proposed Clean Air Transport Rule).

To solve this problem, EPA must adopt a significantly longer compliance deadline. EPA should adopt by rule an across-the-board one-year extension pursuant to 112(i)(3)(B). However, even a four-year compliance period will be inadequate for many affected sources. Therefore, EPA should provide additional time by: (1) granting in the final rule a Presidential extension under 112(i)(4), given that it is in the "national security interests of the United States" to prevent widespread noncompliance in the industrial base; (2) declaring that the statutory three-year compliance period is impossible to meet or otherwise produces "absurd results," which as demonstrated in EPA’s recent PSD Tailoring Rule are doctrines that allow EPA to depart from clear statutory directives in appropriate circumstances; and/or

(3) establishing phased or sequenced requirements such that certain element of the rule become effective no later than three years after promulgation (thus satisfying 112(i)(3)(A)), while others are phased in at later times.

Response: Regarding the commenter's concerns on a reasonable implementation schedule, see response to comment EPA-HQ-OAR-2002-0058-2702.1, excerpt 218.

Commenter Name: Traylor Champion
Commenter Affiliation: Georgia-Pacific LLC
Document Control Number: EPA-HQ-OAR-2002-0058-2745.1
Comment Excerpt Number: 1

Comment: GP has 84 solid fuel and oil-fired boilers subject to Boiler MACT and it is anticipated that all but 2 of these boilers will require addition of one or more add-on devices or modifications/upgrades to combustion systems to meet the proposed limits. The normal duration of GP major capital projects from initial concept to completion is 3 years, consisting of 1 year for technology review and vendor/equipment selection, 1 year for engineering and equipment manufacturing, and 1 year for construction, startup, commissioning and compliance testing. There are a number of factors that will make it very difficult to get all 82 units in compliance within the proposed 3 year time frame.
* Resource limitations
o Internal – The GP corporate engineering group is currently staffed to manage 2-3 major boiler projects at a time. Even if external engineering resources are hired to augment internal resources, we would still need GP engineering/project management to manage and supervise the external resources. Mill staffs can typically manage 1-2 ongoing boiler projects at a time and some of the mills will have as many as 5 boilers that will be impacted by Boiler MACT. Attempting to manage 82 projects concurrently will increase the cost of compliance due to errors and inefficiency.
o External – There are limited engineering, manufacturing and construction resources to design, manufacture and install the required control equipment. All of industry will be placing demand on these resources at the same time. This situation is worse than it normally would be due to the fact that the economy is coming out of a major recession and many of these companies may have significantly reduced their workforce.
o Utility MACT – The utility version of Boiler MACT is expected to go into effect one year after industrial Boiler MACT. Since utilities and industry share the same engineering, manufacturing and construction resource base, we will be competing with the utilities for these resources. The inherent larger size of utility projects will make it difficult for industrial companies to compete.
* Outage scheduling – Large pulp and paper mills with multiple boilers typically stagger boiler outages throughout the year due to resource constraints and to minimize the impact on production. In facilities with multiple boilers requiring addition of control devices, it will be necessary to complete some of the installations as much as 12-15 months prior to the compliance deadline which will significantly compress the normal schedule duration and place additional stress on limited resources.

Response: Regarding the commenter's concerns on a reasonable implementation schedule, see response to comment EPA-HQ-OAR-2002-0058-2702.1, excerpt 218.

Commenter Name: Tom Piccorelli
Commenter Affiliation: Oberlin College
Document Control Number: EPA-HQ-OAR-2002-0058-2961.1
Comment Excerpt Number: 2

Comment: EPA should provide regulatory relief for the regulated community that has provided certification and documentation under 112 (J) filings with individual authorized state agencies to comply with the remanded Boiler MACT. EPA at a minimum, should give consideration to this regulated group with an extended compliance deadline recognizing the expenditures and continuing efforts made during the interim limbo status of the Boiler MACT. A three year extension beyond the proposed three year compliance deadline is suggested. The cost of compliance testing, work practice controls, control technology changes and monitoring system installations to meet the proposed Industrial Boiler MACT standards are high for the degree of emission reductions proposed. Averaging these costs over a period of time may allow for some regulatory relief for this regulated group of boilers whose owners/operators have strived to achieve recognizable progress towards compliance with the remanded MACT.

Response: Regarding the commenter's concerns on a reasonable implementation schedule, see response to comment EPA-HQ-OAR-2002-0058-2702.1, excerpt 218.

Commenter Name: Traylor Champion
Commenter Affiliation: Georgia-Pacific LLC
Document Control Number: EPA-HQ-OAR-2002-0058-2745.1
Comment Excerpt Number: 3

Comment: There is real-life difficulty in meeting a three year compliance deadline for an overwhelming number of major projects, EPA must extend the compliance date beyond three years and even beyond the one-year extensions authorized by 40 CFR §63.6(i)(4)(i). As noted in the AF&PA comments, EPA has several options for accomplishing a significantly longer compliance deadline including (1) a Presidential extension under §112(i)(3)(B) of the CAA, (2) declaring that the statutory deadline is impossible to meet or would produce “absurd results”, and/or (3) establishing phased or sequenced requirements.

Response: Regarding the commenter's concerns on a reasonable implementation schedule, see response to comment EPA-HQ-OAR-2002-0058-2702.1, excerpt 218.

Commenter Name: Duane Mummert

Commenter Affiliation: South Carolina Chamber of Commerce Environmental Technical Committee
Document Control Number: EPA-HQ-OAR-2002-0058-3171
Comment Excerpt Number: 5

Comment: Air construction permits will be required for these changes in South Carolina. The pending uncertainly and complexity of green house gas regulation under the Clean Air Act and the Tailoring Rule will be added to this process and the ETC is concerned South Carolina Department of Health and Environmental Control and EPA will not be able to issue permits in a timely manner.

Response: Regarding the commenter's concerns on a reasonable implementation schedule, see response to comment EPA-HQ-OAR-2002-0058-2702.1, excerpt 218.

Commenter Name: Paul Lyskava
Commenter Affiliation: Pennsylvania Forest Products Association
Document Control Number: EPA-HQ-OAR-2002-0058-2906.1
Comment Excerpt Number: 6

Comment: Revise and extend the compliance deadline beyond the proposed three-years in order to mitigate the economic impacts associated with the extensive demand for retrofits and limited technical and financial resources currently available to support these retrofits. A phased or sequenced compliance schedule should be considered.

Response: Regarding the commenter's concerns on a reasonable implementation schedule, see response to comment EPA-HQ-OAR-2002-0058-2702.1, excerpt 218.

Commenter Name: Nina E. Butler
Commenter Affiliation: Smurfit-Stone Container Corp.
Document Control Number: EPA-HQ-OAR-2002-0058-2783.1
Comment Excerpt Number: 8

Comment: Smurfit-Stone also believes that a compliance period longer than three years also is needed to ensure that the numerous legal and implementation questions regarding this Proposed Boiler MACT are resolved sufficiently for industry to make informed decisions about compliance options and adequately plan for the major capital expenditures that will be required.

Response: Regarding the commenter's concerns on a reasonable implementation schedule, see response to comment EPA-HQ-OAR-2002-0058-2702.1, excerpt 218.

Commenter Name: Gary Chandler
Commenter Affiliation: Association of Washington Business
Document Control Number: EPA-HQ-OAR-2002-0058-2914.1
Comment Excerpt Number: 9

Comment: Extending the compliance period. Owners and operators will be required to retrofit numerous industrial boilers and process heaters to comply with the final rule. The proposed three-year compliance timeline is exceedingly short, given what is required to retrofit boilers. AWB requests that EPA adopt a significantly longer compliance deadline and establish a phased-in approach for compliance with the new standards.

Response: Regarding the commenter's concerns on a reasonable implementation schedule, see response to comment EPA-HQ-OAR-2002-0058-2702.1, excerpt 218.

Commenter Name: Jennifer Klein
Commenter Affiliation: Ohio Chamber of Commerce
Document Control Number: EPA-HQ-OAR-2002-0058-2901.1
Comment Excerpt Number: 10

Comment: Owners and operators will undoubtedly be required to retrofit countless industrial boilers and process heaters in order to meet the final rule. The current proposal sets a three-year compliance deadline for existing affected sources. This is an exceedingly short time given the extensive nature of the needed retrofits and the limited technical resources available to accomplish the retrofits. To solve this problem, EPA should adopt a significantly longer compliance deadline.

Response:

Commenter Name: Martha E. Rudolph
Commenter Affiliation: State of Colorado
Document Control Number: EPA-HQ-OAR-2002-0058-2940.1
Comment Excerpt Number: 12

Comment: The regulatory impacts of these rules may take effect sooner than EPA anticipates because the Definitions Rule implementation schedule is unclear. It is unclear whether or not the Definitions Rule requirements apply earlier than the Boiler/Process Heater MACT, Area Source Boiler Rule and CISWI proposals. Thus materials may need to be diverted much sooner than the applicability dates of the Boiler/Process Heater MACT, Area Source Boiler Rule and CISWI in order to comply with the effective date of the Definitions Rule. In that event, permitting revisions to authorize the change in materials burned would be necessary.

Response: Regarding the commenter's concerns on a reasonable implementation schedule, see response to comment EPA-HQ-OAR-2002-0058-2702.1, excerpt 218.

Commenter Name: Edward E. Quick
Commenter Affiliation: Celanese International Corp
Document Control Number: EPA-HQ-OAR-2002-0058-2840.1
Comment Excerpt Number: 15

Comment: The proposed compliance deadline in the rule is unreasonable and should be extended by an additional 2 years.

EPA should use the discretion it has under the Clean Air Act to provide a longer compliance period than the 3 year period in the proposed rule. Celanese recognizes that newly promulgated NESHAP regulations have traditionally specified a 3-year compliance schedule (with the potential for an additional year). In most previously promulgated NESHAP, this period was sufficient to allow for compliance. However, due to several factors, we feel that the traditional period is inadequate for the proposed regulation.

A significant amount of testing will be required by sources to determine the compliance status with respect to the rule and to evaluate and select available control strategies. Capital projects to install necessary control equipment cannot proceed until the testing and evaluation is complete. Due to the high number of sources affected by the rule that have the same concerns, it is likely that availability of stack testing personnel and laboratory facilities to conduct tests will be limited, adding to the time required to complete this essential first step.

The proposed rule will likely require control equipment to reduce very dilute concentrations of pollutants (such as dioxins). Control equipment vendors have little to no experience at designing controls for such low concentrations, and a period of research and development will be required to design adequate control strategies. This situation is different from most NESHAPs that have been proposed to date where the technology for the required emission reductions was well-known and demonstrated.

To comply with the proposed regulation, Celanese may choose to replace coal-fired boilers at one of its sites with natural gas-fired units. In addition to the lengthy process to obtain capital, design, permit, and install the boilers, the site is located in an area that is not adequately served by natural gas distribution system, and will require construction of an entirely new 16-mile pipeline to provide sufficient natural gas. Such a project will require an extensive and time-consuming permitting process.

Boilers and process heaters are somewhat unique in that they are essential to most portions of a plant, and projects to upgrade or replace boilers will need to occur during scheduled plant-wide shutdowns. There are limited windows of opportunity for such shutdowns, which will serve to lengthen the time needed to implement them.

Response: Regarding the commenter's concerns on a reasonable implementation schedule, see response to comment EPA-HQ-OAR-2002-0058-2702.1, excerpt 218.

Commenter Name: David W. Peightal
Commenter Affiliation: Dakota Gasification Company
Document Control Number: EPA-HQ-OAR-2002-0058-3179
Comment Excerpt Number: 16

Comment: In the event of any new MACT standards being promulgated, DGC would need more time than the proposed three years in order to assess impact of the rule. This assessment would subsequently involve consideration of the availability of resources, engineering involvement, technology options, and new equipment installation. EPA should consider the number of sources affected by this rule and the availability of advanced technological equipment that would be required by those affected sources.

Response: Regarding the commenter's concerns on a reasonable implementation schedule, see response to comment EPA-HQ-OAR-2002-0058-2702.1, excerpt 218.

Commenter Name: Gary W. Kruger
Commenter Affiliation: Morton Salt
Document Control Number: EPA-HQ-OAR-2002-0058-2883.1
Comment Excerpt Number: 16

Comment: EPA Should Extend the Compliance Deadline for Existing Affected Sources.
EPA proposes to set the compliance deadline for existing affected sources at 3 years after the date of publication of the final rule in the Federal Register. We believe this provides an insufficient amount of time for the thousands of affected sources to be retrofitted as necessary to meet the new MACT standards. EPA estimated that 3,730 existing units will have to come into compliance with the proposed MACT standards. This is an unprecedented number of sources impacted by a MACT ruling. These units are all solid fuel-fired, mostly coal-fired, units. In order to meet the MACT standards, owners will, by and large, have to install add-on controls. The additional controls installed to meet the previously vacated Boiler MACT are likely not sufficient to meet the emission limits of the proposed rule, so additional controls will be necessary. Experience with the previously vacated Boiler MACT has demonstrated that this timeline is not adequate to conduct the required emissions testing and engineer and install additional controls for these units.

Response: Regarding the commenter's concerns on a reasonable implementation schedule, see response to comment EPA-HQ-OAR-2002-0058-2702.1, excerpt 218.

Commenter Name: Gary W. Kruger

Commenter Affiliation: Morton Salt
Document Control Number: EPA-HQ-OAR-2002-0058-2883.1
Comment Excerpt Number: 17

Comment: We anticipate severe time and material constraints that will make it extremely difficult, if not impossible, to meet the retrofit deadline of 3 years. Design, procurement, installation, and shakedown of these projects will easily consume 3 years. More time is needed for this. External factors such as the large number of companies competing for limited resources and materials from engineering consultants, equipment vendors, construction contractors, financial institutions, and other critical suppliers will also jeopardize the 3-year compliance deadline.
It is likely we will be unable to procure the necessary goods and services to complete the retrofitting of affected units within 3 years. We anticipate problems procuring scrubbers because immediate industry demand will outstrip immediately available supplies. In addition, we must continue to operate as best as possible while retrofitting to meet the new MACT standards. The existing solid fuel-fired boilers that will be subject to this new rule comprise the most critical part of the base load energy supply for our facilities. Units typically have high capacity utilization rates, and extensive outages for retrofitting must be carefully planned.
We do not believe 3 years is sufficient to allow us the time necessary to make the retrofits without substantial disruption to the operation of our facilities.

Response: Regarding the commenter's concerns on a reasonable implementation schedule, see response to comment EPA-HQ-OAR-2002-0058-2702.1, excerpt 218.

Commenter Name: Gary W. Kruger
Commenter Affiliation: Morton Salt
Document Control Number: EPA-HQ-OAR-2002-0058-2883.1
Comment Excerpt Number: 18

Comment: We recommend EPA extend the compliance deadline to 4 years after the publication of the final regulations in the Federal Register. We believe the Agency would be fully justified in invoking § 112(i)(3)(B) to grant owners of all affected sources a 1-year extension of the compliance deadline. Four years would provide critically needed time for us to conduct the necessary retrofitting with controls and absorb the great cost of these retrofits. Given the magnitude of the retrofit requirements and the likelihood of substantial difficulties fulfilling these requirements, it is essential that EPA provide whatever relief may be possible. The 1-year compliance extension authorized by the Act is a legitimate and necessary solution to this problem, and we urge EPA to incorporate a general 1-year compliance extension for existing affected sources in the final Boiler MACT rule.

Response: Regarding the commenter's concerns on a reasonable implementation schedule, see response to comment EPA-HQ-OAR-2002-0058-2702.1, excerpt 218.

Commenter Name: American Crystal Sugar Company and Michigan Sugar Company
Commenter Affiliation: Patricia Hansen and Steven Smock
Document Control Number: EPA-HQ-OAR-2002-0058-2970.1
Comment Excerpt Number: 21

Comment: All companies which were on schedule to be compliance with the vacated boiler MACT installed any needed additional controls for the vacated Boiler MACT. Many have expressed an opinion that the proposed boiler MACT will be tested in the courts. All of the sources should be granted an extension of the compliance date until a reasonable time after the any changes resulting from any decisions of the court have been finalized. Two years after the court's decision should be sufficient time to finish engineering decisions and complete installation. If the agency makes enough improvements to the Boiler MACT that litigation does not occur then the extension should not active.

Response: Regarding the commenter's concerns on a reasonable implementation schedule, see response to comment EPA-HQ-OAR-2002-0058-2702.1, excerpt 218.

Commenter Name: Paul N. Cicio
Commenter Affiliation: Industrial Energy Consumers of America
Document Control Number: EPA-HQ-OAR-2002-0058-2752.1
Comment Excerpt Number: 21

Comment: PSD Tailoring Rule - The facility upgrades needed to comply with the boiler MACT must be exempted from the PSD Tailoring Rule to be able to meet the boiler MACT compliance schedule.
Facilities will have to install extensive emission control equipment to meet the proposed Boiler MACT emission limits. Specifically, EPA stated in the preamble that emission control would likely require a fabric filter (FF) plus carbon injection plus wet scrubber control plus combustion improvements or carbon monoxide (CO) catalyst. These installations will be long, involved engineering projects that will be difficult to complete in the 3 year compliance timeframe, particularly given that most facilities must continue to operate during the upgrades. Many facilities have numerous boilers which cannot be shutdown simultaneously, so the equipment installation will start well before the end of the three years. This will create significant challenges, which could become impossible to overcome if regulatory hurdles, uncertainty or inactions occur. Therefore the facility upgrades needed to comply with the boiler MACT must be exempted from the PSD Tailoring Rule to be able to meet the boiler MACT compliance schedule.
The installation of the extensive emissions control equipment could result in increases in emissions of CO_2 or another criteria pollutant. The following are examples:
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(1) In general the installation of additional emission control equipment will increase the pressure drop that a boiler's induced draft (ID) fan will have to overcome. If the ID fan is not upgraded the boiler steaming capacity will decrease because the previous air–to-fuel ratio cannot be

achieved resulting in the requirement to increase the firing rate of the other facility boilers. Combustion of additional fuel in the other on-site boilers may result in a significant emissions increase triggering PSD.
(2) Operation of additional emissions control equipment will require more electricity. A facility's unused electrical generating capacity would be required to meet this demand thereby requiring additional fuel combustion. Combustion of additional fuel may result in a significant emissions increase triggering PSD.
Facilities may be required to make operational changes in order to meet the Boiler MACT limits that could result in increases in emissions of CO_2 or another criteria
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pollutant. The following are examples:
(1) Fuel switching for multi-fuel boilers may be required to meet the proposed boiler MACT emission limits. A specific example is multi-fuel (e.g. wood and some coal) boiler that has over-fired air that decreases emissions of CO and it must combust additional coal in order to further decrease the emissions of CO. This change in firing ratio of fuels may result in a significant increase triggering PSD.
(2) A biomass boiler may have to increase its operating target for excess oxygen level in order to decrease emissions of CO in order to meet the proposed boiler MACT emission limit. The result is that the flue gas flow rate increases to a level that is beyond the capability that existing fabric filter can handle reliably and the amount of fuel that can be burned in this boiler is now administratively limited to match the capability of the fabric filter. This requires that the facility operate the back-

up natural gas package boilers which have no heat recovery system (e.g. economizer or air heater) to make-up the difference rather than invest in a larger
fabric filter needed to meet the proposed Boiler MACT limits. This change requiring additional combustion of natural gas may result in a significant increase triggering PSD.
There are many other ways that the PSD tailoring rule could be triggered due to changes that facilities must make to achieve compliance with the proposed Boiler MACT rule.
Another complicating issue is that EPA has not provided guidance on what is required for BACT for CO2e. A tremendous amount of time and effort has gone into BACT determinations for criteria pollutants over the last decade and an equal or larger effort will be required for BACT determinations for CO2e.
The timeline for compliance with Boiler MACT is to install emission control equipment by 2013. Permitting work for installation will be required two or more years prior to 2013, meaning that the PSD tailoring rule will apply to larger facilities within this time frame. Therefore, these larger facilities will have to evaluate whether or not the project to comply with Boiler MACT triggers PSD. These evaluations are very complicated and take time to ensure the facility retains the maximum operating flexibility possible due to the compounding effect of changes to all the boilers at a facility. Decreasing one pollutant may increase another, and addition of controls to decrease the increased pollutant may require other operational changes. In addition, smaller facilities may have to perform this evaluation out of an abundance of caution because there is no guarantee that the higher tailoring rule applicability threshold will be accepted due to the pending evaluation that states are making to determine whether their statutory thresholds of 100/250 ton per year can be changed. Pending legal challenges may also result in lower thresholds as well. Facilities that trigger PSD and their state regulators will be faced with BACT determinations for

CO2e and in all likely-hood will have little-to-no guidance from EPA at that time. Many states make no decisions about PSD without EPA guidance because they fear that EPA will not agree with their determinations or that some non-government organization will file a legal challenge. The result will be catastrophic because no decisions will be made and the facility will have no clear decisions at the time money needs to be spent to purchase and install equipment.
The theme of uncertainty is of critical importance because the long-term viability of a facility and its associated jobs are dependent on capital spending to ensure its continued competitiveness. Developing countries have none of these rules thereby making investment (e.g. moving a U.S. facility's production to another country) financially attractive and there is far less uncertainty.
In order to remove some of this uncertainty, the EPA should categorically exempt projects required to comply with Boiler MACT from additional regulatory burdens such as PSD. A less desirable alternative is allowing an extended compliance timeline for a Boiler MACT project that triggers PSD. This can be facilitated by starting the three year compliance timeline for Boiler MACT when the construction permit (or Title V permit modification) is issued by the administrative authority. This approach ensures that the affected source and state have come to agreement on permit requirements (e.g. stakeholders have sufficient BACT guidance and associated information) and it provides time for installation of a well engineered project that will meet all the regulatory requirements.

Response: Regarding the commenter's concerns on a reasonable implementation schedule, see response to comment EPA-HQ-OAR-2002-0058-2702.1, excerpt 218.

Commenter Name: Edward E. Quick
Commenter Affiliation: Celanese International Corp
Document Control Number: EPA-HQ-OAR-2002-0058-2840.1
Comment Excerpt Number: 24

Comment: Celanese will be challenged to complete the pipeline and boiler conversion within the 3-year compliance window allowed by the proposed rule.

Response: See response to comment EPA-HQ-OAR-2002-0058-2765.1, excerpt 25.

Commenter Name: Barry Christensen
Commenter Affiliation: Occidental Chemical Corp
Document Control Number: EPA-HQ-OAR-2002-0058-2848.1
Comment Excerpt Number: 26

Comment: EPA should allow postponement of stack testing if it is not possible to burn alternative fuels. The rule should be modified to incorporate an option to request an extension for completion of the performance test if a facility currently does not have a fuel onsite. Several of our sites are permitted to burn fuel oil, but do not currently have it available onsite. If the price of natural gas rises dramatically, we will need to convert quickly to burning fuel oil. Allowing an extension of time in the rule will help the facility adjust to adverse economic situations while still ensuring air quality protection.

Response: The facility is responsible for demonstrating that they are able to continuously comply with the emissions limits when operating under expected operating conditions. If a stack test does not represent the range of combined process and control measure conditions under which the facility expects to operate, the delegated agency may determine that retesting is warranted. EPA notes that the agency will have three years to obtain liquid fuel to the site if a facility identifies certain units as belonging to the liquid fuel subcategory. The final rule has added several provisions to accommodate periodic use of liquid fuels, without subjecting a unit to the liquid fuel subcategory. For example, if a unit only fires liquid fuels during periods of gas curtailment or emergency, or periodic testing, the unit would be in the gas 1 subcategory (which does not have emission limits) and it would be unnecessary to conduct performance testing on the liquid fuel. If the unit routinely fires liquid fuels, it is expected that the facility could obtain necessary fuel supply in order to demonstrate compliance with the standards.

Commenter Name: Robert Thornton
Commenter Affiliation: International District Energy Association
Document Control Number: EPA-HQ-OAR-2002-0058-2918.1
Comment Excerpt Number: 28

Comment: IDEA believes EPA's current schedule, with promulgation by December 16, 2010 is inadequate for the necessary evaluations, deliberations, and revisions that are needed to this Proposed Rule. This rule in combination with the three other proposed combustion rules presents the largest set or rulemakings from an impact and cost perspective that EPA has ever issued. As such, the cost and potential impact on jobs in the US demand a thorough deliberation and thought process so that the most reasonable and defensible rule can be finalized that meets the intentions of the Clean Air Act. Requiring EPA to do all of the work required in less than 4 months puts EPA in an untenable position and the results of having too little time will be a less than optimum regulatory result.

Further, given both the significant cost for design and construction of facilities to meet the standards and the current constraints on access to capital (particularly for colleges, universities and other institutions), the three year deadline for compliance will be onerous.

Response: Regarding the commenter's concerns on a reasonable implementation schedule, see response to comment EPA-HQ-OAR-2002-0058-2702.1, excerpt 218.

Commenter Name: Jerry Osheka
Commenter Affiliation: PPG Industries
Document Control Number: EPA-HQ-OAR-2002-0058-2938.1
Comment Excerpt Number: 29

Comment: EPA Should Provide for a Compliance Period Longer Than 3 Years. It is apparent that, even with the changes suggested above, owners and operators will be required to retrofit countless industrial boilers and process heaters in order to meet the final rule. The proposal would set a three-year compliance deadline for existing affected sources. However, this is an exceedingly short time given the extensive nature of the needed retrofits and the limited technical resources available to accomplish the retrofits. In addition, industrial boiler owners will be competing for equipment and technical resources with other key industry sectors such as the utility sector, which will have a similar compliance deadline for the utility MACT and also will be required to install substantial air pollution controls to meet the proposed Clean Air Transport Rule.

To solve this problem, EPA must adopt a significantly longer compliance deadline. Nominally, EPA should adopt by rule an across-the-board one-year extension pursuant to § 112(i)(3)(B). However, even a four-year compliance period will be inadequate for many affected sources. Therefore, EPA should provide additional time by: granting in the final rule a Presidential extension under § 112(i)(4), given that it is in the "national security interests of the United States" to prevent widespread noncompliance in the industrial base; declaring that the statutory three-year compliance period is impossible to meet or otherwise produces "absurd results," which as demonstrated in EPA's recent PSD Tailoring Rule are doctrines that allow EPA to depart from clear statutory directives in appropriate circumstances; and/or establishing phased or sequenced requirements such that certain element of the rule become effective no later than three years after promulgation (thus satisfying § 112(i)(3)(A)), while others are phased in at later times.

Response:

Commenter Name: David M. Kiser
Commenter Affiliation: International Paper Company
Document Control Number: EPA-HQ-OAR-2002-0058-2777.1
Comment Excerpt Number: 31

Comment: The magnitude of the engineering task alone to research the capabilities of technologies to achieve such stringent proposed standards, assess compliance approaches and conduct engineering assessments to determine the feasibility of achieving compliance and the estimated cost to do so is easily a 6 month project even on a fast track. Control options conceivably needed to achieve proposed limits have never been applied to boilers of the size and design of those common to the pulp and paper industry (e.g., combustion catalysts and carbon impregnated filters for dioxins) and actual research is needed to assess feasibility. Then, because fuels may become unavailable for use as solid wastes or may be needed to assure compliance (e.g., natural gas), there is the need to assess availability of alternative fuels and consider the infrastructure needed to deliver and use them.

EPA must provide adequate implementation time, beyond the typical three year compliance window, to allow for transitioning away from alternative fuels, if necessary, and sufficient time to allow for the deluge of facilities who will call upon boiler and control system specialty firms to do the herculean task to retrofit tens of thousands of combustion units all across the country while minimizing economic impact on a fragile US economy. More time will definitely be necessary so that permitting of new and/or modified equipment can also occur. The dollars associated with complying with this suite of rules competes with the dollars that are also necessary to meet other EPA initiatives such as GHG, water and other air initiatives. The pool of available dollars is not without limits.

Response: Regarding the commenter's concerns on a reasonable implementation schedule, see response to comment EPA-HQ-OAR-2002-0058-2702.1, excerpt 218.

Commenter Name: Christopher S. Colman
Commenter Affiliation: Hovensa LLC
Document Control Number: EPA-HQ-OAR-2002-0058-2863.1
Comment Excerpt Number: 38

Comment: Another reason we believe that treatment under Section 125(h) is warranted is that installing multiple control technologies on 23 oil fired units at HOVENSA is simply not technically or economically feasible in the three years (plus one possible year of extension) provided by the Clean Air Act. The logistical difficulties of construction in remote areas were outlined above, and it is simply not possible to design, procure and install control equipment of this magnitude in the three years allowed.
Moreover, as discussed in detail above, the installation of these controls requires shutdown of the units that they service. Installation would have to be done unit by unit (shutting the refinery down is impractical and the logistics of installing 23 units' add-on controls all at once is also impractical). Doing this in addition to engineering and procurement in the space of 3 years is just not physically possible.

Response: Regarding the commenter's concerns on a reasonable implementation schedule, see response to comment EPA-HQ-OAR-2002-0058-2702.1, excerpt 218.

Commenter Name: Sarah E. Amick
Commenter Affiliation: Rubber Manufacturers Association
Document Control Number: EPA-HQ-OAR-2002-0058-2941.1
Comment Excerpt Number: 42

Comment: It is apparent that, even with the changes suggested above, owners and operators would be required to retrofit countless industrial boilers and process heaters in order to meet the final rule. The proposal would set a three-year compliance deadline for existing affected sources. However, this is an exceedingly short time given the extensive nature of the needed retrofits and the limited technical resources available to accomplish the retrofits (especially in light of the fact that industrial boiler owners would be competing for equipment and technical resources with other key industry sectors such as the utility sector, which would have a similar compliance deadline for the utility MACT and also would be required to install substantial air pollution controls to meet the proposed Clean Air Transport Rule).

To solve this problem, EPA must adopt a significantly longer compliance deadline. Nominally, EPA should adopt by rule an across-the-board one-year extension pursuant to § 112(i)(3)(B). However, even a four-year compliance period would be inadequate for many affected sources. Therefore, EPA should provide additional time by: (1) granting in the final rule a Presidential extension under § 112(i)(4), given that it is in the "national security interests of the United States" to prevent widespread noncompliance in the industrial base; (2) declaring that the statutory three-year compliance period is impossible to meet or otherwise produces "absurd results," which as demonstrated in EPA's recent PSD Tailoring Rule are doctrines that allow EPA to depart from clear statutory directives in appropriate circumstances; and/or (3) establishing phased or sequenced requirements such that certain element of the rule become effective no later than three years after promulgation (thus satisfying § 112(i)(3)(A)), while others are phased in at later times.

Response: Regarding the commenter's concerns on a reasonable implementation schedule, see response to comment EPA-HQ-OAR-2002-0058-2702.1, excerpt 218.

Commenter Name: Alicia Oman
Commenter Affiliation: National Association of Manufacturers
Document Control Number: EPA-HQ-OAR-2002-0058-2845.1
Comment Excerpt Number: 45

Comment: EPA proposes to set the compliance deadline for existing affected sources at three years after the date of publication of the Final Rule in the Federal Register. It will be extraordinarily difficult – if not impossible – for all of the entities with existing boilers to make the changes necessary to comply with this rule in the three year timeframe that EPA proposes. Put simply, the normally herculean task of performing a boiler retrofit in three years will be made impossible by the enormous competition for critical resources and the likely gridlock in many state permitting processes that the broad application of this rule will create. Many boiler owners will be simply unable to secure equipment and assistance and/or to obtain the state/local permits needed to retrofit their units within three years.

Even under the best of circumstances, a major retrofit of a boiler takes years from project start to finish. EPA has estimated that the installation of an activated carbon injection control system on one combustion unit – a comparatively simple installation – takes about 15 months. [Footnote: EPA, Engineering and Economic Factors Affecting the Installation of Control Technologies for Multipollutant Strategies (2002).] However, EPA expects a range of control devices will be used to meet the standards, including fabric filters, carbon bed adsorbers, activated carbon injection, electrostatic precipitators, wet scrubbers, replacement burners, and combustion controls.

[Footnote: EPA, Regulatory Impact Analysis: National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters, 3-1 (April 2010) ("The control analysis considered fabric filters, carbon bed adsorbers, and activated carbon injection to be the primary control devices for mercury control, electrostatic precipitators for units meeting mercury limits but requiring additional control to meet the PM limits, wet scrubbers to meet the HCl limits, tune-ups, replacement burners, and combustion controls for CO and organic HAP control, and carbon injection for dioxin/furan control.")] Further, the sheer number of boilers impacted by the rule will make finding – and then scheduling – the design and construction resources almost impossible. EPA estimates that there are approximately 13,555 units located at 1,608 facilities covered by this rule. 75 Fed. Reg. 32048. Given that EPA has set emissions standards that no existing unit can meet, every single existing unit subject to an emission standard may need to be retrofitted. Boiler owners will need to hire consultants to assist them in designing and performing the retrofit. Thus, across the multitude of industries impacted by this rule, boiler owners will be competing for qualified consultants to design, permit and perform the retrofits necessary to make boilers compliant with this stringent rule. There are only a limited handful of consulting companies with the expertise to assist in such retrofits, and they will likely be unable to assist all of the boiler owners in less than three years. There will be a similar scarcity in equipment vendors, construction contractors, construction equipment (e.g, heavy lifting cranes), skilled labor (e.g., boilermakers), and other critical suppliers. Companies may even be unable to secure the basic building materials and control equipment (e.g., baghouses and scrubbers).

Response: Regarding the commenter's concerns on a reasonable implementation schedule, see response to comment EPA-HQ-OAR-2002-0058-2702.1, excerpt 218.

Commenter Name: Alicia Oman
Commenter Affiliation: National Association of Manufacturers
Document Control Number: EPA-HQ-OAR-2002-0058-2845.1
Comment Excerpt Number: 46

Comment: EPA should extend the compliance deadline given the breadth of sources and competition for resources.

In order to retrofit a boiler, the owner will need to line up the capital necessary to pay for the retrofit. In these difficult economic times, just securing the necessary capital may take months, if not years. In addition, the owner will need to go though the relevant permitting process(es), which will similarly take months, if not years. Finally, once the finances are secure and the permitting is complete, the owner will actually need to perform the retrofit. The design, procurement, installation, and shakedown of a retrofit project (e.g., installing a scrubber on a large boiler) can easily take more than three years.

In addition, the timing of the retrofit work needs to be carefully planned, particularly for boilers that provide the primary and/or base load energy supply for their facilities. A facility owner will only shut down a boiler when everything is properly staged to ensure minimal disruption of the facility's operation. In addition to ensuring that the design work is completed and the control equipment and other supplies are on-site and ready for installation, the facility owner needs to make sure that the full suite of consultants and laborers are available for the installation. Based on a discussions with a number of potentially affected companies, the turnaround or shutdown cycles for boilers at many of the facilities is so long as to make this type of precise staging exceedingly difficult to do in a three year period without substantial business interruption.

Response: Regarding the commenter's concerns on a reasonable implementation schedule, see response to comment EPA-HQ-OAR-2002-0058-2702.1, excerpt 218.

Commenter Name: Alicia Oman
Commenter Affiliation: National Association of Manufacturers
Document Control Number: EPA-HQ-OAR-2002-0058-2845.1
Comment Excerpt Number: 47

Comment: In many instances, the installation of pollution control equipment and associated charges to boiler must be permitted under state air pollution statutes and/or construction codes (building permits, etc.). The proposed rule will result in an increase in the number of permit applications, potentially swamping the state and local agencies. Even in those areas where the rule may not result in significant increases in permitting work, the normal delays associated with permitting may make meeting the three year compliance deadline impossible.

In light of the difficulty in meeting a three year compliance deadline, EPA and authorized states should be prepared to readily grant one-year extensions under CAA 112(i)(3)(B) to those units that have problems installing the necessary control equipment to comply with the industrial Boiler MACT rule.

Response: Regarding the commenter's concerns on a reasonable implementation schedule, see response to comment EPA-HQ-OAR-2002-0058-2702.1, excerpt 218.

Commenter Name: Kevin M. Dempsey
Commenter Affiliation: American Iron and Steel Institute
Document Control Number: EPA-HQ-OAR-2002-0058-2998.1
Comment Excerpt Number: 47

Comment: It is apparent that, even with the changes suggested above, owners and operators, including iron and steel manufacturing facilities, will be required to retrofit countless industrial boilers and process heaters in order to meet the final rule. The proposal would set a three-year compliance deadline for existing affected sources. However, this is an exceedingly short time given the extensive nature of the needed retrofits and the limited technical resources available to accomplish the retrofits (especially in light of the fact that industrial boiler owners will be competing for equipment and technical resources with other key industry sectors such as the utility sector, which will have a similar compliance deadline for the utility MACT and also will be required to install substantial air pollution controls to meet EPA's proposed Clean Air Transport Rule).

To solve this problem, EPA must adopt a significantly longer compliance deadline. Nominally, EPA should adopt by rule an across-the-board one-year extension pursuant to section 112(i)(3)(B). However, even a four-year compliance period will be inadequate for many affected sources. Therefore, EPA should provide additional time by: (1) granting in the final rule a Presidential extension under section 112(i)(4), given that it is in the "national security interests of the United States" to prevent widespread noncompliance in the industrial base; (2) declaring that the statutory three-year compliance period is impossible to meet or otherwise produces "absurd results," which as demonstrated in EPA's recent PSD Tailoring Rule are doctrines that allow EPA to depart from clear statutory directives in appropriate circumstances; and/or (3) establishing phased or sequenced requirements such that certain element of the rule become effective no later than three years after promulgation (thus satisfying section 112(i) (3) (A)), while others are phased in at later times.

Response: Regarding the commenter's concerns on a reasonable implementation schedule, see response to comment EPA-HQ-OAR-2002-0058-2702.1, excerpt 218.

Commenter Name: Alicia Oman
Commenter Affiliation: National Association of Manufacturers
Document Control Number: EPA-HQ-OAR-2002-0058-2845.1
Comment Excerpt Number: 48

Comment: EPA should establish an extended two-step compliance period for situations where a boiler owner voluntarily elects to replace or retrofit a boiler to burn a cleaner fuel source. [Footnote: EPA recognizes the MACT rule should be crafted to encourage the use of cleaner fuels, such as natural gas. 75 Fed. Reg. 32025.] If a facility decides to switch to a cleaner fuel, the replacement or retrofit work required to make that switch will potentially take years, for all of the reasons discussed above. Rather than require the facility to add emissions controls to its existing boiler in time for the proposed three year compliance deadline – likely eliminating the possibility that the facility would switch to a cleaner fuel source – EPA should allow six years total for facilities to change their boilers and meet the MACT requirements for the cleaner fuel source. This six year period would occur in two steps; a no-backsliding provision would apply for three years from publication of the rule in the Federal Register, and then the facility would have three years to comply with MACT standard for the subcategory for the cleaner fuel subcatetory. EPA promulgated exactly this type of extended MACT compliance deadline for certain facilities that voluntarily elected to install new technology as part of the Pulp and Paper Cluster Rule. See Pulp and Paper Cluster Rule, 60 Fed. Reg. 18503, 18,508 (Apr. 15, 1998). [Footnote: This two-step approach for the MACT standard is consistent with the D.C. Circuit's decision in NRDC v. EPA, 89 F.3d 1364 (D.C. Cir. 2007) (finding invalid EPA's decision to extend the compliance deadline for a promulgated MACT rule by a year because of the substantial changes that the agency made to the rule). Rather than functioning as an extension of the compliance deadline, this MACT standard for certain facilities would become applicable in two steps. For the first three years, a no-backsliding MACT standard would be applicable, then the three year deadline to implement the MACT standard for the applicable “cleaner” source would begin to run.] In addition to providing an incentive for facilities to switch to cleaner fuel sources, this approach would reduce some of the competition for resources discussed above by extending the deadline to complete the work to replace or retrofit certain boilers.

Response: Regarding the commenter's concerns on a reasonable implementation schedule, see response to comment EPA-HQ-OAR-2002-0058-2702.1, excerpt 218.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 232

Comment: EPA SHOULD ALLOW A LONGER COMPLIANCE TIMEFRAME. EPA proposes to set the compliance deadline for existing affected sources at three years after the date of publication of the Final Rule in the Federal Register. It will be extraordinarily difficult – if not impossible – for all of the entities with existing boilers to make the changes necessary to comply with this rule in the three year timeframe that EPA proposes. Put simply, the normally herculean task of performing a boiler retrofit in three years will be made impossible by the enormous competition for critical resources and the likely gridlock in many state permitting processes that the broad application of this rule will create. Many boiler owners will be simply unable to secure equipment and assistance and/or to obtain the state/local permits needed to retrofit their units within three years.

Even under the best of circumstances, a major retrofit of a boiler takes years from project start to finish. EPA has estimated that the installation of an activated carbon injection control system on one combustion unit – a comparatively simple installation – takes about 15 months. [EPA, Engineering and Economic Factors Affecting the Installation of Control Technologies for Multipollutant Strategies (2002).] However, EPA expects a range of control devices will be used to meet the standards, including fabric filters, activated carbon injection, electrostatic precipitators, wet scrubbers, replacement burners, and combustion controls. [EPA, Regulatory Impact Analysis: National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters, 3-1 (April 2010) ("The control analysis considered fabric filters, carbon bed adsorbers, and activated carbon injection to be the primary control devices for mercury control, electrostatic precipitators for units meeting mercury limits but requiring additional control to meet the PM limits, wet scrubbers to meet the HCl limits, tune-ups, replacement burners, and combustion controls for CO and organic HAP control, and carbon injection for dioxin/furan control.")] Further, the sheer number of boilers impacted by the rule will make finding – and then scheduling – the design and construction resources almost impossible. EPA estimates that there are approximately 13,555 units located at 1,608 facilities covered by this rule.[75 Fed. Reg. at 32048.]

Given that EPA has set emissions standards that only a handful of existing units can currently meet, almost every single existing unit subject to an emission standard will need to be retrofitted. Boiler owners will need to hire consultants to assist them in designing and performing the retrofit. Thus, across the multitude of industries impacted by this rule, boiler owners will be scrambling to find the very few qualified consultants who can perform the retrofits necessary to make boilers compliant with this stringent rule. There are a limited number of consulting companies with the expertise to assist in such retrofits, and they will likely be unable to assist all of the boiler owners in less than three years, especially when the electric utility industry will be competing for the same resources in order to comply with their own MACT standard. There will be a similar scarcity in equipment vendors, construction contractors, construction equipment (e.g., heavy lifting cranes), skilled labor (e.g., boilermakers), and other critical suppliers. Companies may even be unable to secure the basic building materials and control equipment (e.g., baghouses and scrubbers).

In order to retrofit a boiler, the owner will need to line up the capital necessary to pay for the retrofit. In these difficult economic times, just securing the necessary capital may take months, if not years, assuming the capital can be obtained from lending sources. In addition, the owner will need to go though the relevant permitting process(es), which will similarly take months, if not years. Finally, once the finances are secure and the permitting is complete, the owner will actually need to perform the retrofit. The design, procurement, installation, and shakedown of a retrofit project (e.g., installing a scrubber on a large boiler) can easily take more than three years.

An example of a rulemaking that involved control retrofits over an extended compliance period is the implementation of the 1-hour ozone SIP requirements in Houston, Galveston, and Brazoria Counties in Texas. Due to the magnitude of the NOx emissions reductions required and the number of sources affected, emission reduction projects were implemented over a 6-year timeframe (2001-2007), with a total capital investment of over $3 billion. As the Boiler MACT will involve more significant emission controls retrofits, it is appropriate to allocate a longer compliance timeframe.

In addition, the timing of the retrofit work needs to be carefully planned, particularly for boilers that provide the primary and/or base load energy supply for their facilities. A facility owner will only shut down a boiler when everything is properly staged to ensure minimal disruption of the facility's operation. In addition to ensuring that the design work is completed and the control equipment and other supplies are on-site and ready for installation, the facility owner needs to make sure that the full suite of consultants and laborers are available for the installation. Based on discussions with a number of potentially affected companies, the turnaround or shutdown cycles for boilers and process heaters at many of the facilities can vary from 1 to 5 years, making this type of precise staging exceedingly difficult to do in a three year period without substantial business interruption.

Response: Regarding the commenter's concerns on a reasonable implementation schedule, see response to comment EPA-HQ-OAR-2002-0058-2702.1, excerpt 218.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 233

Comment: In many instances, the installation of pollution control equipment and associated charges to boiler must be permitted under state air pollution statutes and/or construction codes (building permits, etc.). The proposed rule will result in an increase in the number of permit applications, potentially swamping the state and local agencies. Even in those areas where the rule may not result in significant increases in permitting work, the normal delays associated with permitting may make meeting the three year compliance deadline impossible.

In light of the difficulty in meeting a three year compliance deadline, EPA and authorized states should be prepared to readily grant one-year extensions under CAA section 112(i)(3)(B) to those units that have problems installing the necessary control equipment to comply with the final rule.

Response: Regarding the commenter's concerns on a reasonable implementation schedule, see response to comment EPA-HQ-OAR-2002-0058-2702.1, excerpt 218.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 234

Comment: EPA should establish an extended two-step compliance period for situations where a boiler owner voluntarily elects to replace or retrofit a boiler to burn a cleaner fuel source. [EPA recognizes the MACT rule should be crafted to encourage the use of cleaner fuels, such as natural gas. 75 Fed. Reg. 32025.] If a facility decides to switch to a cleaner fuel, the replacement or retrofit work required to make that switch will potentially take years, for all of the reasons discussed above. Rather than require the facility to add emissions controls to its existing boiler in time for the proposed three year compliance deadline – likely eliminating the possibility that the facility would switch to a cleaner fuel source – EPA should allow six years total for facilities to change their boilers and meet the MACT requirements for the cleaner fuel source. This six year period would occur in two steps; a no-backsliding provision would apply for three years from publication of the rule in the Federal Register, and then the facility would have three years to comply with MACT standard for the subcategory for the cleaner fuel subcategory. EPA promulgated exactly this type of extended MACT compliance deadline for certain facilities that voluntarily elected to install new technology as part of the Pulp and Paper Cluster Rule. [See Pulp and Paper Cluster Rule, 60 Fed. Reg. 18503, 18508 (Apr. 15, 1998). This two-step approach for the MACT standard is consistent with the D.C. Circuit’s decision in NRDC v. EPA, 89 F.3d 1364 (D.C. Cir. 2007) (finding invalid EPA’s decision to extend the compliance deadline for a promulgated MACT rule by a year because of the substantial changes that the Agency made to the rule). Rather than functioning as an extension of the compliance deadline, this MACT standard for certain facilities would become applicable in two steps. For the first three years, a no-backsliding MACT standard would be applicable, then the three year deadline to implement the MACT standard for the applicable "cleaner" source would begin to run.] In addition to providing an incentive for facilities to switch to cleaner fuel sources, this approach would reduce some of the competition for resources discussed above by extending the deadline to complete the work to replace or retrofit certain boilers.

Response: Regarding the commenter's concerns on a reasonable implementation schedule, see response to comment EPA-HQ-OAR-2002-0058-2702.1, excerpt 218.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 235

Comment: Alternatively, in light of the significant challenges presented by the breadth and number of boilers in the source category, which are discussed above, EPA, the Department of Energy and the Department of Commerce should prevail upon the President to exempt sources from compliance with the standards for a period of not more than 2 years based on a determination that the technology to implement the standards is not available and it is in the national security interests of the United States to do so. As discussion elsewhere in these comments makes clear, the control technology that would allow boilers to meet the proposed stringent suite of standards simply does not exist. Further, even if the agencies determine that such control technology exists, it will not be "available" for most boilers because of the resource limitations discussed above. Granting an extension under section 112(i)(4) is in the national security interests of the United States in order to avoid the widespread shutdown of non-retrofitted boilers that a three year compliance deadline would demand. The boilers impacted by this rule power almost every sector of the United States economy, including sectors that provide critical supplies to the nation’s security infrastructure.

Response: Regarding the commenter's concerns on a reasonable implementation schedule, see response to comment EPA-HQ-OAR-2002-0058-2702.1, excerpt 218.

Commenter Name: Wayne Brandt
Commenter Affiliation: Minnesota Forest Industries
Document Control Number: EPA-HQ-OAR-2002-0058-3220
Comment Excerpt Number: 13

Comment: Extend the Compliance Deadline.
The three year compliance deadline must be extended for existing sources. It is unreasonable to expect that all of the sources that must retrofit can accomplish the necessary testing, systems design and engineering and equipment production when thousands of facilities are seeking these services. Section 112(i)(4) provides the legal basis for an extended compliance period.

Response: Regarding the commenter's concerns on a reasonable implementation schedule, see response to comment EPA-HQ-OAR-2002-0058-2702.1, excerpt 218.

Other - Compliance

Commenter Name: Steven M. Maruszewski
Commenter Affiliation: The Pennsylvania State University
Document Control Number: EPA-HQ-OAR-2002-0058-2729.1
Comment Excerpt Number: 12

Comment: The regulation needs to be clarified that any increases in NOx emissions as a result of the annual boiler tune-up to minimize CO emissions will not be a violation of existing permit conditions.

Response: The tune-up requirement should not result in substantial increases in NOx because sources are only required to tune the boiler to manufacturer's specifications. NOx emissions become higher when the boiler combustion is adjusted (tuned) to lower CO levels than those for which the boiler was designed (manufacturer's specification) to operate. Further, we have modified the language in the tune-up from "minimize" CO to "optimize" CO in order to consider the trade-off between NOx and CO emissions, and the focus of many state boiler tune-up programs which focus on minimizing NOx emissions, while optimizing combustion efficiency.

Commenter Name: Steven M. Maruszewski
Commenter Affiliation: The Pennsylvania State University
Document Control Number: EPA-HQ-OAR-2002-0058-2729.1
Comment Excerpt Number: 17

Comment: Fuel switching – NSR penalty
New Source Review is an unintended consequence of switching to a cleaner fuel. One of the Boiler MACT responses available to the University is fuel switching to natural gas. The University currently combusts 2 trillion Btu’s a year . Of that total,
97% is from the combustion of bituminous coal and the remaining 3% is from the combustion of natural gas. Should the University switch to firing all natural gas, the Pennsylvania Department of Environmental Protection (DEP) has determined that an
NSR applicability determination will be done comparing past natural gas to future natural gas. This determination will certainly trigger NNSR for NOx, and PSD for CO. The University believes this to be an unintended negative consequence. It
seems incongruous that taking an action that will result in significant decreases in emission, will result in this stringent a permit review. Based on past stack tests, the decrease in emissions in

tons per year, will be: carbon monoxide = 140, nitrogen oxides = 235, sulfur oxides = 1920, HCl = 237, and carbon dioxide = 73,300. The per cent decrease for each of these pollutants will be: 65%, 63%, 99.9%, 100%, and 40% respectively. Penn State suggests that EPA address this in the guidance documents to
state agencies, specifically that the decision on NSR applicability is on a source by source basis and not on a fuel by fuel basis.

Response: EPA acknowledges the concerns of the commenter. A final response on guidance provided to state agencies on NSR applicability as it relates to requirements of this rule are outside the scope of this comment response document.

Commenter Name: Ted Sturdevant
Commenter Affiliation: Washington Department of Ecology
Document Control Number: EPA-HQ-OAR-2002-0058-2987.1
Comment Excerpt Number: 4

Comment: For a rule of this complexity and wide scope, it is essential that EPA provide guidance for implementation at or near the time when the final rule is issued. Affected facilities and state, local, or tribal agencies will necessarily rely on EPA's guidance for the successful implementation of the NESHAP standards.

Response: EPA plans to issue guidance and outreach for implementing this rule in the future.

Commenter Name: Chris Korleski
Commenter Affiliation: Ohio EPA
Document Control Number: EPA-HQ-OAR-2002-0058-2818.1
Comment Excerpt Number: 14

Comment: For a rule of this complexity and wide scope, it is essential that US EPA provide guidance for implementation when the final rule is issued or at a minimum set a date of issuance of guidance. Affected facilities and state, local, or tribal agencies will necessarily rely on EPA's guidance for the successful implementation of the NESHAP standards.

Response: See response to comment EPA-HQ-OAR-2002-0058-2987.1, excerpt 4 for discussion of guidance and outreach.

Commenter Name: American Crystal Sugar Company and Michigan Sugar Company
Commenter Affiliation: Patricia Hansen and Steven Smock
Document Control Number: EPA-HQ-OAR-2002-0058-2970.1
Comment Excerpt Number: 19

Comment: In the previous Boiler MACT and all other Boiler regulations there is a slight but significant difference in the group sizing.
All previous regulations grouped by: Boilers 100 MMBtu/hr; Boilers > 100 MMBtu/hr; and < 250 MMBtu/hr; Boilers > 250 MMBtu/hr

The proposed Boiler MACT grouped by: Boilers < 100 MMBtu/hr;Boilers 100 MMBtu/hr and < 250 MMBtu/hr; Boilers 250 MMBtu/hr

Why has the EPA adjusted the range for the size categories? It is requested that the Boiler MACT size classification be changed to reflect all other boiler regulations.

Response: In the final rule, the size threshold of 100 mmBtu/hr is no longer relevant since there are no CO CEMS requirements in the final rule. We have modified the threshold of 250 mmBtu/hr to be greater than 250 mmBtu/hr instead of greater than or equal to 250 mmBtu/hr in order to be consistent with the size thresholds in the New Source Performance Standards for Industrial/Commercial/Institutional boilers and process heaters (40 CFR part 60 subpart Db).

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 238

Comment: In section 63.7525(a), Performance Specification 4A is required for CO CEMS. This performance specification was primarily developed for CEMS intended to demonstrate compliance with CO emission standards less than 200 ppmv. As the proposed rule includes CO limits for some units that are greater than 200 ppmv, EPA should also allow the use of Performance Specification 4, which was designed for CO span values in the 1000 ppmv range.

Response: A CO CEMS is no longer a requirement in the final rule and we have removed discussion of PS 4A from the rule language.

Impacts Analysis

Costs: Control Technology Assumptions

Commenter Name: Dwayne Arino
Commenter Affiliation: Jeld-Wen, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-0856.1

Comment Excerpt Number: 2

Comment: These suggested limits will be near impossible to achieve without installation of additional pollution controls, i.e., above controls already mandated by current regulation. Units with current pollution controls not meeting these standards will be required to retrofit, replace, or either install additional controls. In short, this proposed rule potentially suggests compliance can be achieved by installing additional end-of-pipe controls on the end of existing end-of-pipe controls.

The estimated const for retrofitting, replacing, or installing additional controls in existing biomass boilers to meet these proposed standards falls between $10 million and $20 million per boiler. This enormous cost would divert valuable dollars to fund a program having little to no real human health or environmental benefits.

Response: See preamble for response.

Commenter Name: Norbord Industries
Commenter Affiliation: Norbord Industries
Document Control Number: EPA-HQ-OAR-2002-0058-0854.1
Comment Excerpt Number: 5

Comment: Reviewing the emission standards and potential emission control equipment for HCl and particulate, Norbord became aware that it's current ESP system at some facilities would likely not be able to comply with the PM standard if the need to control HCl (most likely lime injection) becomes necessary. Control technologies for HCl would add quite a bit of particulate loading to the system not to mention the likelihood a wet system will likely be required as well to bring the HCl levels to the extremely low standard set. This would require that the ESPs be removed for a system capable of handling high moisture levels or a lime injection system installed after the ESP along with additional PM controls. This is not even taking into consideration the potential need to control mercury and dioxins/furans.

Additionally, it appears EPA did not take into consideration the costs associated with the need to radically change current control systems, burners and even fuels. Norbord is aware that other entities will be providing more specific cost data, but EPA should take the cost of this rule much more seriously. Did EPA take into consideration the cost requirements to comply with other MACT standards as well? Did EPA take into consideration the havoc it's creating with all the different scenarios needed to comply with such an overly strict rule? In at least the wood products industry many mills are spending more than a million dollars a year on gas costs for HAP reduction. Many of these facilities were forced to close in recent years and many more will close if this rule is not changed.

Response: See response for DCN EPA-HQ-OAR-2002-0058-3213.1, Excerpt Number 20.

Commenter Name: Charles McRae
Commenter Affiliation: Rex Lumber
Document Control Number: EPA-HQ-OAR-2002-0058-1846
Comment Excerpt Number: 3

Comment: The cost of controls is millions of dollars per boiler at a typical wood products facility, and you still may not meet the limits.

Response: See response for DCN EPA-HQ-OAR-2002-0058-1779, Excerpt Number 78.

Commenter Name: A. Daniel White
Commenter Affiliation: T.R. Miller Mill Company, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-1597.1
Comment Excerpt Number: 3

Comment: TRM asked a consultant for a preliminary cost estimate to achieve compliance to the new rules. An ESP, catalytic oxidizer, a wet scrubber, a bag house, major duct work, and permitting would be required for each boiler. The estimated cost for both boilers -- $6 million to $12 million! This does not include the increased ongoing operating costs. The consultant is concerned that even at this exorbitant cost, compliance may not be achieved.

Response: See response for DCN EPA-HQ-OAR-2002-0058-1779, Excerpt Number 78.

Commenter Name: Houston Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1876
Comment Excerpt Number: 3

Comment: While I'm not ready to discuss specific
cost projections for my facility, the figures for the
forest product industry in Mississippi are indicative.
In Philadelphia, we would need to consider adding on at
least three control devices to address at least four of
the five hazardous air pollutants that EPA has proposed to strengthen and regulate on the Boiler MACT group, and
we would have to do so not knowing whether the controls
with extremely low levels of pollutants such as mercury
and dioxides would be effective or could even be
measured with certain. There's got to be a better way.
What we'd like EPA to do with the cost impacts for the
rules that are proposed so large, and numerous technical

issues that others will detail, we urge EPA to make this
a win-win and use its discretion and improve the rules
significantly to reduce the compliance cost.

Response: See preamble for response.

Commenter Name: Los Angeles Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1778
Comment Excerpt Number: 14

Comment: Our rough estimate of $1.5 million to attempt to get close to the limit for the main boiler at Flambeau River Papers does not even ensure that compliance will be met with these proposed limits. Flambeau River Papers is a small one-mill company that is striving to lead the forest products industry environmentally.

Response: See response for DCN EPA-HQ-OAR-2002-0058-1779, Excerpt Number 78.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute and National Petrochemical and Refiners Association
Document Control Number: EPA-HQ-OAR-2002-0058-0851.1
Comment Excerpt Number: 16

Comment: Since the proposed emission limits are unachievable simultaneously and at all operating conditions while meeting applicable NOx limits without add-on controls, all gas and liquid units subject to emission limits will have to install CO controls, rather than just some units as EPA assumed. Many, in addition to those identified in the Agency estimates, will also have to install PM, Hg and HCl controls to handle normal variability, since those limits apply at all times. For the limited number of units that may be able to meet the proposed CO limits at all times without oxidation catalyst, SCR controls for NOx will often be needed because low-CO operating conditions greatly increase NOx production. In these cases, costs and burdens reflecting increased energy consumption and increased CO_2 emissions must also be included in the estimates.

A significant percent of units will be unable to add controls to the existing unit because of space or structural constraints and thus replacement units will need to be constructed at greatly increased cost. The RIA estimates included no costs or burdens for replacement units or for installing CO controls on most Gas 2 and liquid fired units. Additionally, no costs were included for lost production while the boiler or process heater was being replaced or for the costs associated with such replacement units having to meet new source standards rather than existing source standards.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2698.1, Excerpt Number 14.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute and National Petrochemical and Refiners Association
Document Control Number: EPA-HQ-OAR-2002-0058-0851.1
Comment Excerpt Number: 18

Comment: It is unclear from our preliminary review of the EPA cost analyses that process heaters were appropriately handled. Process heaters are not boilers and estimates based on boiler information are incorrect. If, in fact, the process heater cost estimates were scaled from estimates for adding controls to boilers, the process heater costs are likely to be grossly underestimated.

Response: See preamble for response.

Commenter Name: Los Angeles Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1778
Comment Excerpt Number: 31

Comment: The cost of adding controls for many biomass boilers covered by the MACT rule, and especially the GACT rule, will exceed the original capital costs of the boiler, or even the cost of a new one. If a biomass GACT source is unable to achieve the carbon monoxide limits by simple means such as combustion controls, more exotic technologies will be needed.

Response: See preamble for response.

Commenter Name: Los Angeles Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1778
Comment Excerpt Number: 36

Comment: A lot of the speakers talk about biomass. We recently

had a large biomass plant apply to our energy commission here in California for permits. And their estimated emissions limits were higher than if they were going to burn coal.
And actually there was a major report released yesterday on biomass burning and how many of the states back east are meeting their portfolio standards by cutting down their forests and burning wood. So the whole concept of biomass burning and whether it’s really a good idea or not bears some scrutiny.

Response: Whether or not biomass burning is a good idea is outside the scope of this rulemaking.

Commenter Name: Los Angeles Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1778
Comment Excerpt Number: 48

Comment: The forest products industry has projected new equipment required in the proposed rules will cost more than $6 billion over a three-year-compliance period plus billions more in subsequent years for operating and maintenance expense. Those capital costs alone exceed the profit in the recent years.

Response: See preamble for response.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute and National Petrochemical and Refiners Association
Document Control Number: EPA-HQ-OAR-2002-0058-0851.1
Comment Excerpt Number: 2

Comment: Where these costs are unsupportable or where the emission limits still could not be met, units and processes would have to shutdown to avoid non-compliance, with resulting economic and job loss.

The costs for such replacements and the full extent of controls were not considered in the cost and burden analyses for Gas 2 sources or for the alternate Gas 1 proposal presented to OMB for review or in the rulemaking record and the impact of shutting down processes and job loss were not addressed. It is our opinion that it cannot have been Congress's intent for EPA to set emission limits without regard to feasibility or their impact on the sources being regulated or the impact on the economy in general. Consideration of the actual costs and burdens and the economic impacts of imposing emission limits on gas-fired boilers and process heaters further supports the conclusion that applying emission limitations to Gas 1 units is infeasible and demonstrates that that same conclusion should be reached for Gas 2 units.

Response: See response for DCN EPA-HQ-OAR-2002-0058-1876, Excerpt Number 3.

Commenter Name: Los Angeles Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1778
Comment Excerpt Number: 33

Comment: While EPA states that fuel switching is not part of their control strategy, the reality is that operators may find it cheaper to purchase a new gas-fired boiler than to put controls on existing biomass units. So much for transitioning to a sustainable energy economy.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2506.1, Excerpt Number 21.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute and National Petrochemical and Refiners Association
Document Control Number: EPA-HQ-OAR-2002-0058-0851.1
Comment Excerpt Number: 9

Comment: Inspection of the estimate details supports our belief of a significant undercounting. For instance, the proposal RIA4 reports there are 199 existing units nationally that fire Gas 2 (gases other than natural gas and refinery gas). This is clearly an unreasonably low number. Our members alone account for more than 180 boilers and process heaters in Gas 2 service at major sources. Since the RIA estimates, in Table 3-1, annualized O&M costs of $500 million per year for just these 199 units, the national impact of underestimating their number is clear.

Response: EPA has adjusted its definition of gas 2 units and the revised estimates were adjusted downward to consider the revised definition. EPA also incorporated new data received on other units that were not previously included in the inventory for major source boilers and process heaters.

Commenter Name: Fred L. Taylor
Commenter Affiliation: Troy Lumber Company
Document Control Number: EPA-HQ-OAR-2002-0058-1879
Comment Excerpt Number: 2

Comment: This regulation will require us to install additional particulate (PM) control devices and continuous opacity monitors as well as to perform Energy Assessments and annual stack and fuel testing on both of our boilers. It could not come at a worse time! With a compliance date of 3 years from final approval of this regulation, we find ourselves in the middle of a crippling economic downturn where many industries are moving off-shore. We are struggling to stay in business as it is.

Emissions Standards:
Current Boiler Emissions = 0.135 lb PM/mmBTU.
The proposed limit for existing Boilers = 0.02 lb PM/mmBTU!
The proposed limit for new Boilers = 0.008 lb PM/mmBTU!
We will also have limits for CO, Hg, HCL, Dioxin / Furan for which we have no idea if we will be compliant or non-compliant.

Attaining the new particulate matter (PM) limit will require $500,000 to $1,000,000 to replace the existing multiclones on our two boilers with baghouses or electrostatic precipitators. Plus, either control device will require extensive, on-going maintenance that will be very expensive. We simply cannot afford such expenditures at this time. Further, the end result will not afford any increase in production throughput and will have minimal impact on our air quality!

Response: See preamble for response.

Commenter Name: Thomas C. Ludlow
Commenter Affiliation: JWTR, LLC
Document Control Number: EPA-HQ-OAR-2002-0058-1870
Comment Excerpt Number: 2

Comment: These rules are estimated to increase costs in Oregon alone by up to $250 million. These increased costs will have a chilling effect on proposed plants that will generate "renewable energy", which seems to be exactly the opposite tact we should be taking for both our environment and economy.

Response: See response for DCN EPA-HQ-OAR-2002-0058-1876, Excerpt Number 3.

Commenter Name: Carl Johnson
Commenter Affiliation: Southern Pressure Treaters' Association

Document Control Number: EPA-HQ-OAR-2002-0058-1867.1
Comment Excerpt Number: 7

Comment: The cost of controls at a typical wood preserving facility would be in the millions of dollars per boiler and still may not meet the proposed limits.

Response: See response for DCN EPA-HQ-OAR-2002-0058-1779, Excerpt Number 78.

Commenter Name: Fred T. Simpson
Commenter Affiliation: Scotch Gulf Lumber, LLC
Document Control Number: EPA-HQ-OAR-2002-0058-1899.1
Comment Excerpt Number: 9

Comment: Scotch Gulf Lumber operates three wood products facilities in Alabama. Each facility contains one biomass-fired boiler that would be required to install costly controls to comply with the proposed Boiler MACT. The cost of additional pollution controls to comply with the proposed rule could exceed $1 million for each facility, and the facilities still may not be able to comply with the carbon monoxide or dioxin/furan emission limits in the proposed rule.

Response: See response for DCN EPA-HQ-OAR-2002-0058-1779, Excerpt Number 78.

Commenter Name: Michael L. Steele
Commenter Affiliation: CraftMaster Manufacturing, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-1907.1
Comment Excerpt Number: 32

Comment: Costs under the alternate definition of solid waste are noted as being lower. Is this due to a lower number of units affected? What is the cost per unit?

Response: EPA did not finalize the alternative definition of solid waste option.

Commenter Name: Arlington Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1779
Comment Excerpt Number: 60

Comment: Municipal electric plants are also concerned with the significant projected cost of the Boiler MACT rule. To install all the control equipment anticipated by the Boiler MACT rule would cost over $20 million for our facility alone. We certainly understand how important it is to protect the environment, and as city officials, we are committed to providing a safe environment for our residents. However, we have to ask ourself this level of expenditure is necessary to protect our citizens and our environment. We think that this rule fails to strike the right balance between job preservation, and growth, and environmental protection.

Response: See response for DCN EPA-HQ-OAR-2002-0058-0856.1, Excerpt Number 2.

Commenter Name: Arlington Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1779
Comment Excerpt Number: 78

Comment: On a financial aspect, the anticipated cost of the rule for Domtar will be well in excess of a hundred million dollars. And even after all these monies have been spent, we cannot guaranty EPA, our stockholders, our employees, our customers, and the public that we will be able to meet the rules at all time because of the issues of variability and -– excuse me -– and the fact that in some cases there are no investments or no technology that is existing out there to actually meet the requirements at all time.

And this is clearly in violation of our own environmental policy which states that we will meet all requirements at all time, and it will cause us to make harsh decision to the future of some of our facilities.

Response: See preamble for response.

Commenter Name: Arlington Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1779
Comment Excerpt Number: 82

Comment: The Catawba mill is one of the most efficient and environmentally friendly mills in the world. We produce coated paper and market pulp. In addition, the mill provides a livable wage for 850 employees.

The continued cumulative impact of EPA regulations is enormous and is putting our industry and many others at a cost disadvantage compared to our worldwide competitors.

The Boiler MACT as issued for my mill alone will require capital expenditures of at least $20 to $40 million and an annual operating cost will range from 4 million to in excess of $7 million.

Response: See response for DCN EPA-HQ-OAR-2002-0058-0856.1, Excerpt Number 2.

Commenter Name: Michael L. Steele
Commenter Affiliation: CraftMaster Manufacturing, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-1907.1
Comment Excerpt Number: 35

Comment: Cost per ton of HAP's Controlled for Biomass Units

Using the data provided in the preamble Tables 10 and 11, the cost per ton of HAP's controlled for the biomass units is significantly higher than the coal-fired and liquid-fired units. HAP's controlled do not include PM.

Biomass $403,258 per ton
Coal $44,094 per ton
Liquid $125,826 per ton

The relatively poor cost-effectiveness for the biomass subcategories in controlling HAP's under the proposed rules provides a strong disincentive to use biomass fuels. This should not be the case given the inherently low emissions of HAPfs and GHG's associated with biomass fuels.

Response: See response for DCN EPA-HQ-OAR-2002-0058-1876, Excerpt Number 3.

Commenter Name: Arlington Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1779
Comment Excerpt Number: 114

Comment: As proposed, the rules impose emission limits with no known means or assurance of achieving them. This will result in incredible uncertainty in the regulated community and a reluctance to invest in the United States.

Response: See response for DCN EPA-HQ-OAR-2002-0058-1779, Excerpt Number 78.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 270

Comment: EPA does not appear to have considered this constraint on availability of control technology for meeting HCl limits at wood products facilities. A wet scrubber or wet ESP may be the only reasonable approach to reducing emissions of particulate and other pollutants regulated by the proposed Boiler MACT and CISWI standards as well. The use of a scrubber or wet electrostatic precipitator on a large boiler at a wood products facility may require the discharge of at least 10 gallons per minute of blowdown (14,400 gallons per day). For facilities subject to a prohibition on wastewater discharge, this control technology would be unavailable as a practical matter. (Additional information about wastewater from pollution control equipment at wood products facilities (in that case, primarily associated with VOC controls) and the difficulties of handling additional wastewater at wood products facilities can be found in AF&PA's March 7, 2003 comments on the proposed Plywood & Composite Wood Products NESHAPS, EPA OAQPS Docket No. A-98-44, Item IV-D-7, which we ask be incorporated by reference in the administrative record for the Boiler MACT rulemaking.)

EPA recognized this same problem when it established MACT standards for the Plywood and Composite Wood Products category. As part of the final MACT standards, EPA amended the definition of "process wastewater" in the Timber Products Processing effluent guidelines to exclude wastewater generated by the types of air pollution control equipment EPA had identified as the basis of MACT standards for those source categories subject to a zero discharge effluent guidelines. See 40 C.F.R. § 429.11(c); 69 Fed. Reg. 45,944 at 45,964 (recognizing that wood products facilities could not meet the zero discharge requirement after complying with the Plywood and Composite Wood Products NESHAPs, "because of the volume of wastewater generated by APCD that are installed to comply with the final PCWP NESHAP and because the technology basis for those effluent limitations guidelines and standards is insufficient, in light of that wastewater volume and the pollutant content, to achieve the prohibition on process wastewater discharges for these NESHAP-related APCD wastewaters").

Response: See preamble for response.

Commenter Name: John Williams
Commenter Affiliation: Maine Pulp and Paper Association
Document Control Number: EPA-HQ-OAR-2002-0058-1913.1
Comment Excerpt Number: 1

Comment: MPPA's members (the "Maine Mills") are very concerned with the potential cost impacts of the Boiler MACT regulation – the American Forest & Paper Association (AF&PA) estimates that compliance with the proposed Boiler MACT rule would cost Maine Mills in excess of $300 million; with compliance costs for certain individual mills in the tens of millions of dollars.

Response: See response for DCN EPA-HQ-OAR-2002-0058-0856.1, Excerpt Number 2.

Commenter Name: Steven Jarvis
Commenter Affiliation: Missouri Forest Products Association
Document Control Number: EPA-HQ-OAR-2002-0058-2384.1
Comment Excerpt Number: 1

Comment: The EPA cites estimated compliance costs at more than $10 billion initially and $4 billion annually for both rules. However, the American Forest & Paper Association (AF&PA) estimates that the initial capital costs for the forest products industry alone may reach $7 billion. The proposed control technology standards are far more stringent than those in the vacated rule, and will present many new challenges for affected facilities.

Response: See response for DCN EPA-HQ-OAR-2002-0058-0856.1, Excerpt Number 2.

Commenter Name: R. Wade Mosby
Commenter Affiliation: The Collins Companies
Document Control Number: EPA-HQ-OAR-2002-0058-2351.1
Comment Excerpt Number: 3

Comment: The Chester, CA plant consists of a sawmill and biomass co-generation power plant that produces 12 MW of electricity. The steam also fires the lumber dry kilns and provides plant heating. This plant provides 108 union (Carpenters & Jointers) family wage jobs and is the largest employer in this small rural Sierra Nevada community. Replacement cost of a boiler with no guarantee of meeting the proposed standards would be approximately $20 million. This facility in 2009 had a payroll of$5.9 million, with $1.8 million in employee related taxes and $606 thousand in local property taxes.

In Lakeview, OR we operate a sawmill with a wood fired boiler that produces steam for the dry kilns and plant heating. This facility employs 76 people with family wage jobs and is the largest private employer in this small rural Eastern Oregon town located 95 miles from the nearest regional shopping and medical facilities. A replacement boiler with no guarantee of meeting the proposed standards would be approximately $ I0 million. The Lakeview facility in 2009 had a payroll of $3 million, with $900 thousand in employee related taxes and paid $110 thousand in local property taxes.

Our Kane, PA facility is a hardwood sawmill and dimension plant that utilizes a wood fired boiler for dry kilns and plant heating. We employ 99 people with family wage jobs and this is the largest private employer in this small rural Northern Appalachian town. A replacement boiler with no guarantee of meeting the proposed standards would run approximately $10 million. The Kane facility had a 2009 payroll of $3.7 million, with $1.1 million of employee related taxes and paid $593 thousand in local property taxes.

Keep in mind that due to the current recession and housing crisis, these plants ran at a one shift reduced basis. In normal times we’d operate at a higher production level with the attendant increase in employment and payroll.

Response: See response for DCN EPA-HQ-OAR-2002-0058-0856.1, Excerpt Number 2.

Commenter Name: Tyler McShan
Commenter Affiliation: McShan Lumber Company
Document Control Number: EPA-HQ-OAR-2002-0058-2207
Comment Excerpt Number: 4

Comment: We have been told that it would cost us hundreds of thousands of dollars to attempt to bring our boiler in compliance with the new regs and there would be no guaranteed result. Again, not a wise investment in what is already a marginal industry.

Response: See response for DCN EPA-HQ-OAR-2002-0058-1779, Excerpt Number 78.

Commenter Name: Jim Hickman
Commenter Affiliation: Langdale Forest Products Co.
Document Control Number: EPA-HQ-OAR-2002-0058-2065.1
Comment Excerpt Number: 5

Comment: The cost of controls is millions of dollars per boiler at a typical wood products facility, and a facility making such an investment may still not be able to achieve the required results.

Response: See response for DCN EPA-HQ-OAR-2002-0058-1779, Excerpt Number 78.

Commenter Name: Kerry Flick
Commenter Affiliation: Metso Power
Document Control Number: EPA-HQ-OAR-2002-0058-2388.1
Comment Excerpt Number: 10

Comment: In regards to the dioxin/furans level, powder activated carbon may be required in order to meet the proposed limits. This will add up-front capital cost as well as operational cost to all new installations. In addition, the use of activated carbon will have a detrimental impact on ash disposal. The higher level of carbon in the ash will make it difficult to sell and will likely lead to controlled ash disposal. a secondary environmental impact not considered in this proposed ruling. There would then be a reduced revenue stream and all added disposal cost.

Response: See preamble for response.

Commenter Name: Britt S. Fleming
Commenter Affiliation: Auto Group
Document Control Number: EPA-HQ-OAR-2002-0058-2775.1

Comment Excerpt Number: 6

Comment: In addition to smaller natural gas-fired boilers/process heaters, EPA is proposing work practices for natural gas-fired boilers/process heaters with a heat input capacity over 10 mmBtu/hour given that the cost of installing controls to comply with emission limits for the five HAP groups is over $14 billion. This number grossly underestimates the cost of add-on controls by excluding the monitoring and operating expenses associated with such equipment. Other industry groups filing comments on this proposal have estimated that the cost of add-on controls for natural gas-fired units in EPA's database alone would be upwards of $51 billion for the subcategory. In reality, this number is likely even higher given that EPA's database does not include all the natural gas units in the country that would be affected by this rule.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2702.1, Excerpt Number 61.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 7

Comment: In this rulemaking, EPA has followed the costing assumptions and techniques in the OAQPS Control Cost Manual (EPA 452/B-02-001). AF&PA continues to believe this approach underestimates the total installed cost of air pollution control equipment, as discussed in previous AF&PA comments submitted on various other proposed emission standards. The Control Cost Manual has not been updated in many years, does not reflect the current costs, and is missing information on several control technologies. While it is recognized EPA is not obligated to consider costs of MACT emission standards when the standards are set at the so-called MACT floor level, AF&PA feels EPA has grossly understated the capital and annualized costs of this proposed rule.
Because of the anticipated major financial impact of this rule on the forest products industry, AF&PA has also estimated the capital costs for installation of additional control technologies on existing boilers. AF&PA did not consider potential cost reductions that might result from emissions averaging, health-based emission limits, or an alternative metals limit in the final rule and we assumed that the Gas 1 emission limits discussed in the preamble would not be promulgated.
We developed a detailed spreadsheet to estimate costs for Boiler MACT, based on EPA's major source boiler inventory database table. Because the proposed rule does not include emission limits for natural gas boilers or boilers less than 10 MMBtu/hr heat input, these units were not included in the cost analysis. Based on the information in the EPA emissions database on boiler size, fuel, existing controls, and emissions, we estimated costs of controls that would likely be necessary to comply with the Boiler MACT for coal, biomass, liquid, and gas 2 boilers. As some forest products boilers at major sources did not receive an ICR from EPA in 2008, we added information for those boilers to the detailed spreadsheet based on a database maintained by Fisher International and information from NCASI. We also estimated costs for a few boilers that

were in the CISWI database but will no longer burn fuels likely to be designated as waste under EPA's proposed approach to defining non-hazardous secondary materials.
Information from various sources [Footnote: See for example "Evaluation of Air Pollution Control Costs for the Pulp and Paper Industry," May 1, 2003, prepared by Stone and Webster Management Consultants for National Economic Research Associates (NERA) and included in Appendix E to these comments.] was used to determine a base capital cost for a 250 MMBtu/hr boiler for each PM and HCl control technology option and then scaled using a 0.6 power function based on the size of each boiler in the inventory. For example, the capital cost of a wet scrubber on a 100 MMBtu/hr boiler is calculated as the base cost times (100/250)0.6. A fixed capital cost of $1 million was assumed for installation of a carbon adsorption system for Hg and/or dioxin control, as these systems do not vary much in cost by boiler size. A fixed capital cost of $2 million was assumed for CO controls (either projects to improve combustion or fuel feed or installation of a CO catalyst). Base cost assumptions are presented in the report contained in Appendix D. It should be noted that the goal was not to create a worst-case cost estimate for each boiler. Rather, the cost estimates represent median costs for the various control scenarios based on published reports, industry and vendor information on specific project costs, EPA reports or control device fact sheets, or actual BACT or BART analyses previously submitted to permitting agencies.
To estimate capital costs for each boiler, we assumed that if there was no emissions information available for a particular boiler, the unit would likely need MACT, which EPA stated in the preamble to the proposed Boiler MACT is a fabric filter (FF) plus carbon injection plus wet scrubber plus combustion improvements (or CO catalyst). For PM, if a unit did not already have a FF or ESP and there was information that indicated the unit cannot meet the proposed limit or there was no emissions information, we assumed a new FF. If the unit already had a FF or ESP and there was information that indicated the unit cannot meet the proposed limit we assumed an upgrade to the existing control equipment. To estimate control costs for HCl, if there was information that indicated the unit cannot meet the proposed limit or if there was no emissions information, we assumed either a scrubber upgrade or new scrubber depending on whether the unit currently had a scrubber. For Hg and dioxin, if there was information that indicated the unit cannot meet the proposed limit or if there was no emissions information, we added carbon injection. For CO, if there was information that indicated the unit cannot meet the proposed limit and is not a fluidized bed boiler, stoker boiler, suspension boiler, or Dutch oven, then we assumed that capital would be necessary to either perform combustion and/or fuel feed improvements or other boiler improvement projects to reduce CO or install a CO catalyst.
Although EPA's estimates indicate that the total capital cost will be $9.5 billion, AF&PA has estimated that the total capital cost of the rule will be over $20 billion for industry, with $6 billion in costs for the forest products industry alone. It is evident major capital investments in add-on control technology will be required for continued operation of solid and liquid fueled boilers at pulp and paper mills and wood products plants.

While the above estimate appears very high compared to the EPA estimate, we believe this estimate to actually be very conservative, since our methodology assumed that controls could actually be installed in a manner that they would achieve the emission levels proposed by EPA overall operating scenarios, including startup and shutdown.

Response: See preamble for response.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 8

Comment: In reality, many units will simply not be able to be retrofit with controls and/or will not be able to meet the emissions limits regardless of controls, so that total combustion unit replacement would be required, which would greatly expand the cost of the rule for individual facilities. That inability to retrofit or meet the emission limits will undoubtedly result in shutdown of marginal production facilities with a loss of jobs and collateral negative economic impact at all social levels. We believe that EPA has failed to consider this highly likely impact since they have simply not considered achievability of the emission limits they are proposing. Without this consideration, the true cost and collateral impacts of the rule are not identified and, therefore, cannot be considered relative to legitimacy of the rulemaking.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2699.1, Excerpt Number 11.

Commenter Name: Richard T. Metcalf
Commenter Affiliation: Louisiana Mid-Continent Oil and Gas Association
Document Control Number: EPA-HQ-OAR-2002-0058-2699.1
Comment Excerpt Number: 10

Comment: EPA needs to consider all costs and burdens in the rule analyses and in the analyses required under other applicable laws and Executive Orders.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2867.1, Excerpt Number 15.

Commenter Name: Richard T. Metcalf
Commenter Affiliation: Louisiana Mid-Continent Oil and Gas Association
Document Control Number: EPA-HQ-OAR-2002-0058-2699.1
Comment Excerpt Number: 11

Comment: Retrofit control costs are underestimated and are not technically or economically feasible in many refinery locations due to a lack of plot space that meets required safety standards. Retrofit controls included in the EPA analysis have not all been demonstrated effective at the low emission limits proposed.

Response: See preamble for response.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 16

Comment: EPA used a catalyst cost of $959.25 per cubic foot from Chapter 2 of the OAQPS Control Cost Manual, according to Table 1 of the ERG cost methodology memo. We assume this means Section 3, Chapter 2, VOC Destruction Controls, dated 2002. Page 2-45 indicates that this cost is based on a 1998 estimate of $650/cubic foot, and we assume that ERG scaled this estimate up to 2008 dollars. Based on a May 2009 cost estimate obtained from BASF by URS Corporation for use in a BACT cost estimate for a CO catalyst on a forest products industry boiler, BASF estimated a cost of $4000 per cubic foot for catalyst modules and supports. As EPA has information from BASF in the docket for this rulemaking, EPA should also have confirmed their cost estimating techniques for CO catalyst installations rather than using outdated cost methodology applicable to catalytic oxidizers for VOC control, which are of different design than a CO catalyst system. EPA should update its CO catalyst costs.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2698.1, Excerpt Number 14.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 17

Comment: We do not agree with the methodology used to determine the cost of CO emissions reductions for boilers with CO emissions less than 400 ppm at 3% O2. The ERG cost and emissions impacts memo states that the cost of a tune-up was estimated if the unit's baseline emissions exceeded the floor for CO but were less than or equal to 400 ppm at 3% O2. Based on conversations with boiler and burner vendors, there are certain boiler and burner designs that cannot achieve the proposed emission limits with a simple tune-up, especially in cases where a low NOx limit must simultaneously be achieved or where biomass is being burned with coal. For combination coal/biomass stoker boilers to achieve the proposed 50 ppm CO limit, it will take more than a tune-up; it will likely take more expensive fuel feed and/or combustion improvements. For many liquid and gas boilers to achieve a 1 ppm CO limit, it will take more than a tune-up; these boilers with low NOx limits will likely face installation of a CO catalyst, which has not been proven to achieve the proposed emission levels or provide an associated reduction in organic HAP emissions. The ability to retrofit CO catalyst systems on all types of existing boilers and process heaters and the effectiveness of these systems in reducing organic HAP emissions are major concerns that need to be addressed by EPA. EPA should re-evaluate its assumptions with respect to feasible options for reductions in CO emissions.
* We do not agree with the methodology used to determine the cost of CO emissions reductions for stoker, fuel cell, and fluidized bed boilers with CO emissions between 400 and 1000 ppm at

3% O2. The ERG cost and emissions impacts memo states that since these boilers do not have replaceable burners, the cost of a linkageless boiler management system (LBMS) was estimated to achieve the MACT floor. An LBMS is not going to be sufficient for a coal/biomass stoker boiler with CO emissions between 400 and 1000 ppm at 3% O2 to achieve 50 ppm CO; it will require the installation of a new overfire air system at a minimum (and possibly a CO catalyst) in order to reduce CO emissions from co-firing coal and biomass to below 50 ppm. Comments on the ability of combination coal/biomass boilers to meet the proposed coal CO emission limits are presented later in this document. Again, EPA should re-evaluate its assumptions with respect to feasible options for reductions in CO emissions.
* We have estimated the cost for CO emissions controls for boilers in the coal and biomass subcategories of $1.2 billion, compared to EPA's cost estimate for the entire rule for CO control of $13.9 million.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2960.1, Excerpt Number 117.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 18

Comment: We do not agree with the methodology used to determine the cost of CO emissions reductions for liquid and gas-fired boilers. The ERG cost and emissions impacts memo states that if baseline CO emissions were between 400 and 1000 ppm for boilers and process heaters designed to burn liquid and gaseous fuels, the cost of a low-NOx burner was estimated to achieve the MACT floor emission limits. The CO limits for these boilers in the proposed rule are 1 ppm. Based on conversations with burner vendors, a low-NOx burner is typically guaranteed to produce CO emissions of 50 to 100 ppm for gas and liquid boilers. EPA's assumption that a burner retrofit will result in achieving the proposed single digit emission limits is simply unfounded. EPA should re-evaluate its assumptions with respect to feasible options for reductions in CO emissions.
* We have estimated the cost for CO emissions controls for boilers in the liquid and gas 2 subcategories of $1.5 billion (assuming controls will achieve 1 ppm CO for all boilers under all operating conditions), compared to EPA's cost estimate for the entire rule for CO control of $13.9 million.
* EPA's cost estimates for CO controls assume that tune-ups and LBMS will achieve very high CO reductions. This assumption is false and is indicative of a lack of recognition of how industrial systems are operated. Much of industry has been operating under extreme financial constraints and lowering costs has been a high priority for a long time. Many combustion units are routinely operated at optimum efficiency so that there is no further opportunity for combustion efficiency adjustment. In fact, EPA's proposed approach to tune-ups (the focus on minimizing CO emissions) will actually in most cases result in use of increased excess air and lead to decreased efficiency and increased emissions overall, counter to EPA's assumption of a 1% efficiency improvement with tune-ups. In the case of biomass boilers, we believe that improvements to fuel feed and combustion air systems that will cost more than the costs

estimated for tune-ups and LBMS are more likely to be required in order to improve the performance of these boilers enough to meet the proposed limits. Addition of overfire air to a large biomass boiler can be at least $500,000. EPA's total estimated capital cost of $13.9 million for combustion controls and oxidation catalysts presented in Table 2 of the cost and emissions impacts memo is extremely low and a gross underestimate of the actual costs that industry boilers will incur to comply with the CO limits in the rule. The liquid and gas 2 limits of 1 ppm in particular will impose extremely high costs for control on some units. EPA should re-evaluate their assumptions with respect to the effect of tune-ups on emission levels and fuel use.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2960.1, Excerpt Number 117.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 19

Comment: EPA has estimated that activated carbon injection will only be required on 155 existing boilers because installation of a fabric filter is expected to achieve the mercury emission limits, except in cases where a unit already has a fabric filter and does not meet the limits. We do not agree that fabric filters will be sufficient to reduce mercury emissions to the ultra low levels proposed in this rule in all cases. There are flaws in EPA's logic that fabric filters are expected to achieve mercury emission limits. First, there are many boilers in the database that are equipped with fabric filters and have measured mercury emissions higher than the proposed limits. Second, when burning fuels containing mercury with fuels containing sulfur (e.g., biomass with TDF, oil, or coal), mercuric sulfate is formed, which is a particulate and can be captured in a fabric filter, but when fuels such as biomass and natural gas with low mercury contents are burned without sulfur-containing fuels, elemental mercury is the primary emission and is not captured in a fabric filter. EPA's estimated industry-wide capital cost for activated carbon injection presented in Table 2 of the cost and emissions impacts memo is extremely low, at only $9.5 million. We do not understand how this can represent 155 boilers; it seems to us to represent the cost 10 boilers would incur to install a carbon injection system. AF&PA's cost estimate for mercury and dioxin/furan controls (carbon injection) is $1.7 billion. EPA should re-evaluate its cost estimates for mercury control.

Response: See preamble for response.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 20

Comment: Per the Methodology for Estimating Cost and Emissions Impacts for Industrial, Commercial, Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants – Major Source document, EPA estimated that an ESP would be installed to meet the PM emissions limit unless a unit already had a fabric filter installed. We believe that since sorbent injection will be required for acid gas, mercury, and dioxin control, that fabric filters will likely be chosen for units without existing ESPs in order to maximize the performance of the sorbents and minimize the amount of sorbent used. For example, use of an ESP will require 4 times the carbon to be injected for mercury/dioxin control than if a fabric filter is used. Using EPA's cost algorithms, installation of a fabric filter has a higher capital cost than installation of an ESP; therefore this assumption results in an underestimate of the capital cost required to meet the proposed PM limits.

Response: See preamble for response.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 21

Comment: EPA has estimated costs to install packed bed scrubbers for HCl control. Industrial boilers do not use packed bed scrubbers for acid gas control, as the limitations of these devices make them impractical for use on applications with high flow rates, high PM loading, and high inlet pollutant concentration. EPA's own fact sheet on these devices, located at http://www.epa.gov/ttn/catc/dir1/fpack.pdf, lists these limitations of these devices and indicates that they are only used in applications up to 75,000 scfm, which limits their use to small units only. Facilities will instead install wet scrubbers, dry scrubbers, or semi-dry scrubbers to control acid gas emissions from industrial boilers. EPA has estimated HCl control costs for equipment that industry is not likely to install. In addition, no consideration was given for facilities that may have zero discharge permits (as many wood products facilities do), where it is infeasible to install a wet control device. EPA should re-evaluate its cost estimates for HCl control. AF&PA has estimated capital costs for HCl control of $9.3 billion, while EPA's capital cost estimate for wet scrubbers is $3.3 billion.

Response: See preamble for response.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 22

Comment: EPA presents several cost options in the two ERG memos. Option 2E assumes that facilities will not incur costs to comply with the dioxin/furan standards because they will test for dioxin/furan and be below detection levels. This logic does not make sense, especially because EPA has not outlined in the rule any procedures for handling non-detects when performing compliance testing and there are boilers in the EPA emissions database with dioxin/furan emissions that are non-detect but actually measured emissions higher than the proposed limit. More detailed comments on detection limit issues and the dioxin/furan emissions data are presented later in this document.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2702.1, Excerpt Number 10.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 199

Comment: The limits being considered for Boiler MACT would necessitate combinations of emission controls that have adverse effects on each other. In other words, the presence of one control technology could prevent a second control technology from operating at optimum performance.

A primary control for Hg emissions involves the injection of activated carbon into the flue gas. The mercury is oxidized on the active sites on the carbon particles. The oxidized form of Hg can then either be recovered by the particulate control equipment, or by the scrubber (since oxidized Hg is soluble). The oxidation reactions only occur at temperatures below about 350ºF. The effectiveness of the activated carbon for oxidizing Hg is dependent upon the amount of time that the carbon has to attract the Hg to one of its active sites.

The use of activated carbon injection for Hg control is negatively affected by the presence of sulfur trioxide (SO3). SO3 occupies the active sites on the carbon, taking away those sites from the Hg. Even a few parts per million of SO3 can have a significant negative impact on the Hg removal that is achieved by activated carbon injection. Small amounts of SO3 are generated as part of the combustion process for sulfur-containing fuels, while the bulk of the sulfur in the fuel is oxidized to SO2. However, other control devices, such as CO oxidation catalyst or SCR NOx reduction catalyst, will convert an additional percentage of the SO2 to SO3, resulting in poor Hg removal.

Response: See preamble for response.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 200

Comment: EPA should also evaluate the data in the database to ensure that boilers can apply additional controls that will achieve the proposed limits. For example, it should examine the percent mercury and HCl reductions necessary for the boilers in a subcategory and, taking into account the fuels burned by the boiler and the controls already in place, EPA should determine if it is even feasible to further control emissions down to levels below the proposed standards.

Response: See response for DCN EPA-HQ-OAR-2002-0058-1779, Excerpt Number 78.

Commenter Name: Richard T. Metcalf
Commenter Affiliation: Louisiana Mid-Continent Oil and Gas Association
Document Control Number: EPA-HQ-OAR-2002-0058-2699.1
Comment Excerpt Number: 12

Comment: EPA has severely underestimated the number of units affected by the control requirements and has therefore underestimated the negative impact of this proposal on the economy and on jobs.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2960.1, Excerpt Number 117.

Commenter Name: Leonard W. Sandridge
Commenter Affiliation: University of Virginia
Document Control Number: EPA-HQ-OAR-2002-0058-2769.1
Comment Excerpt Number: 1

Comment: [See submittal for Table of Capital Cost Estimate for UVA Boilers]

Response: See response for DCN EPA-HQ-OAR-2002-0058-1876, Excerpt Number 3.

Commenter Name: Leonard W. Sandridge
Commenter Affiliation: University of Virginia
Document Control Number: EPA-HQ-OAR-2002-0058-2769.1
Comment Excerpt Number: 2

Comment: Based on our review of the survey database, Major Source Boilers & Process Heaters Inventory Table, for UVA sources (Facility ID = VAUniversityofVirginia), we noticed that our 11 boilers over 10 MMBtu/hr heat input that are designed to burn natural gas and distillate oil are classified as gas 1 subcategory boilers. While oil may not be routinely combusted in these boilers, some fire enough oil to exceed the 10% heat input threshold in the definition of a gas 1 subcategory. At a minimum, Boilers 5575-1-01 through -04, 7103-1-03R, 7103-1-04R, 7533-1-01 and 7533-1-02 should be classified in the liquid subcategory; these boilers are at our district heating plants and we may need the operating flexibility to burn gas or oil. EPA's estimates of the compliance costs should be updated to reflect the higher compliance costs associated with existing liquid fire boilers.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2506.1, Excerpt Number 21.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-2702.1
Comment Excerpt Number: 2

Comment: EPA's estimated costs of the rule are significantly lower that the real cost impact on sources. Although EPA's estimates indicate that the total capital cost of the Proposed Rule will be $9.5 billion, CIBO and URS have estimated that the total capital cost of the rule will be over $20 billion for all affected sources for installation of emissions controls on coal, liquid, and Gas 2 boilers. Major capital investments in add-on control technology will be required for continued operation of the industrial, commercial and institutional (ICI) power house and energy base of the country.

Based on EPA's major source boiler inventory database,which includes information on boiler size, fuel, existing controls, and emissions, we estimated costs of controls that would likely be necessary to comply with the Boiler MACT for coal, biomass, liquid, and Gas 2 boilers for units 10 MMBtu/hr and greater. Because the Proposed Rule does not include emission limits for natural gas boilers, these units were considered in a separate cost analysis assuming the work practice standards would not be allowed and the proposed Gas 1 limits in the preamble would be applied, requiring application of control technology to these boilers and process heaters for all regulated pollutants.

Information from various sources was used to determine a base capital cost for a 250 MMBtu/hr boiler and process heater for each PM and HCl control technology option and then scaled using an 0.6 power function based on the size of each boiler and process heater in the inventory. For example, the capital cost of a scrubber on a 100 MMBtu/hr boiler is calculated as the base cost of $8 million times (100/250)0.6. A fixed capital cost of $1 million was assumed for installation of a carbon adsorption system for Hg and/or dioxin control, as these systems do not vary much in cost by boiler size. A fixed capital cost of $2 million was assumed for CO controls (either projects to improve combustion or fuel feed or installation of a CO catalyst). Base cost estimates represent median costs for the various control scenarios based on published reports, industry and vendor information on specific project costs, EPA reports or control device fact sheets, or actual BACT or BART analyses previously submitted to permitting agencies.

To estimate capital costs for each boiler and process heater, we assumed that if there was no emissions information available for a particular unit, the unit would likely need MACT, which EPA stated in the preamble to the proposed Boiler MACT is a fabric filter (FF) plus carbon injection plus wet scrubber plus combustion improvements (or CO catalyst). For PM, if a unit did not already have a FF or ESP and there was information that indicated the unit cannot meet the proposed limit or there was no emissions information, we assumed a new FF. If the unit already had a FF or ESP and there was information that indicated the unit cannot meet the proposed limit we assumed an upgrade to the existing control equipment. To estimate control costs for HCl, if there was information that indicated the unit cannot meet the proposed limit or if there was no emissions information, we assumed either a scrubber upgrade or new scrubber depending on whether the unit currently had a scrubber. For Hg and dioxin, if there was information that indicated the unit cannot meet the proposed limit or if there was no emissions information, we added carbon injection. For CO, if there was information that indicated the unit cannot meet the proposed limit and is not a fluidized bed boiler, stoker boiler, suspension boiler, or dutch oven, then we assumed that capital would be necessary to either perform combustion and/or fuel feed improvements or other boiler/process heater improvement projects to reduce CO or install a CO catalyst.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2792.1, Excerpt Number 126.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-2702.1
Comment Excerpt Number: 3

Comment: EPA has used the outdated Control Cost Manual and we have based our cost estimates on more recent information, including actual vendor cost estimates, actual project costs, BACT and BART analyses, industry control cost studies, etc.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2901.1, Excerpt Number 1.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-2702.1
Comment Excerpt Number: 4

Comment: We used a CO catalyst cost 4 times higher than EPA's. The CIBO/URS estimate is based on a recent quote from BASF and EPA's is based on the 1998 Control Cost Manual section on catalytic oxidizers for VOC control.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2698.1, Excerpt Number 14.

Commenter Name: Arnold Schwarzenegger
Commenter Affiliation: Governor Arnold Schwarzenegger
Document Control Number: EPA-HQ-OAR-2002-0058-2697.1

Comment Excerpt Number: 4

Comment: The proposed MACT Standards did not take into account the technological and economic feasibility for some of the existing BTE facilities to meet the proposed emission limits. The supporting documentation to the MACT Standards stated that boilers with CO emission levels between 400 parts per million (ppm) and 1,000 ppm (at 3 percent 02) could install a Linkageless Burner Management Systems (LBMS) for under $20,000 dollars. However, there is no documentation that these systems can or have been successfully retrofitted to existing BTE facilities using stoker or fuel cell oven combustion to achieve the proposed levels. For units burning biomass, the draft regulatory analysis estimated that 72 percent of the units are exceeding the MACT floor emission limits, and that these units would need to install an LBMS. Based on ARB staff conversations with several stoker burner manufacturers, we could find no stoker units that have been retrofitted with these systems. Further, these manufacturers stated that a successful retrofit to meet the proposed standards was doubtful based on the inherent leakage of air in these types of facilities. In consulting with several LBMS manufacturers, none of these manufacturers were aware of any retrofits of stoker type boilers with a LBMS system. ARB recommends U.S. EPA conduct a more thorough analysis of the feasibility and costs for existing biomass facilities utilizing stoker or fuel cell/Dutch oven combustors to be retrofitted with a LBMS system.

Response: See preamble for response.

Commenter Name: David A. Buff
Commenter Affiliation: Golder Associates Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2801.1
Comment Excerpt Number: 4

Comment: Total cost of compliance extremely high for each mill due to the large number of boilers

* ESP to meet PM limits – $2 to $3 million capital cost per boiler

* Regenerative selective catalytic reduction (RSCR) to meet CO limit – $5 million minimum capital cost per boiler (assuming this technology is feasible on a bagasse boiler)

* Cost to replace a boiler with necessary controls: $30 to $50 million

* Average cost per boiler ~ $10 to $15 million

* Total cost to sugarcane processing industry ~ $250 to 350 million

Even most large industrial sources such as paper mills have only one or two boilers subject to rule; three individual sugar mills will have five or six boilers subject to the rule; one mill will have four boilers; and one mill will have three boilers

Response: See response for DCN EPA-HQ-OAR-2002-0058-0856.1, Excerpt Number 2.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-2702.1
Comment Excerpt Number: 5

Comment: EPA has estimated that a tuneup or burner replacement will be adequate for many units to achieve the CO limits. We do not agree with this assumption and have estimated higher costs to implement combustion controls, fuel feed system improvements, or CO catalyst.

Our estimated CO control capital costs are $1.2 billion for liquid and gas 2 and $1.5 billion for coal and biomass, where EPA's total estimate for CO control capital costs is only $13.9 million, mostly because they have assumed that tune-ups and replacement burners will be adequate for the vast majority of boilers to comply.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2960.1, Excerpt Number 117.

Commenter Name: David A. Buff
Commenter Affiliation: Golder Associates Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2801.1
Comment Excerpt Number: 6

Comment: Comments on EPA's Cost Numbers and Approaches

EPA's cost impact figures are much lower than those projected by industry. This is likely due to an underestimate of the number of boilers that will require new air pollution control equipment due to the Industrial Boiler MACT limits. As described above, about 90 percent of the sugar industry's boilers will not be able to meet the proposed MACT standards based on current operation. EPA has likely not anticipated that many boilers may have to shut down rather than face the expensive task of retrofitting. If a plant or mill continues to operate, it may need to totally replace one or more boilers, as the existing boilers will not be able to meet the new limits even using the most advanced air pollution control equipment.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2699.1, Excerpt Number 11.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-2702.1

Comment Excerpt Number: 6

Comment: EPA has estimated that activated carbon injection will only be required on 155 existing boilers because installation of a fabric filter is expected to achieve the mercury emission limits, except in cases where a unit already has a fabric filter and does not meet the limits. We do not agree that fabric filters will be sufficient to reduce mercury emissions to the ultra low levels proposed in this rule. There is a flaw in the logic that fabric filters are expected to achieve mercury emission limits when there are many boilers in the database that are equipped with fabric filters and have measured mercury emissions higher than the proposed limits. EPA's estimated industry-wide capital cost for activated carbon injection presented in Table 2 of the cost and emissions impacts memo is extremely low, at only $9.5 million. We do not understand how this can represent 155 boilers; it seems to us to represent the cost 10 boilers would incur to install a carbon injection system. Our estimate for carbon injection required for mercury and dioxin/furan control is $1.7 billion.

Response: See response for DCN EPA-HQ-OAR-2002-0058-3213.1, Excerpt Number 19.

Commenter Name: William R. Ermatinger
Commenter Affiliation: Northrop Grumman
Document Control Number: EPA-HQ-OAR-2002-0058-2506.1
Comment Excerpt Number: 7

Comment: The capital cost to replace the NGSB "powerhouse" boilers, consisting of three residual oil-fired units, is estimated at between $30 million and $50 million. Even if modifications to, or replacement of, the boiler burners would allow the successful combustion of light distillate oil in lieu of residual fuel oil in the NGSB boilers, the additional cost of burning light distillate oil would increase NGSB operating costs by nearly $8 million annually based on fuel cost alone. In addition, boiler efficiency would suffer by as much as 4% when burning light distillate oil, directly thwarting EPA's goal of increasing boiler efficiency as a means of reducing HAPs. EPA erred when it did not take into account such cost and efficiency penalties in its regulatory impact analysis. Furthermore, even if light distillate oil could be successfully combusted, the NGSB boilers would still not be able to meet the proposed Boiler MACT emission limitations for liquid fuel-fired units.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2506.1, Excerpt Number 21.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-2702.1
Comment Excerpt Number: 7

Comment: EPA estimated that an ESP would be installed to meet the PM emissions limit unless a unit already had a fabric filter installed. We believe that since sorbent injection will be required for acid gas, mercury, and dioxin control, that fabric filters will likely be chosen for units without existing ESPs in order to maximize the performance of the sorbents and minimize the amount of sorbent used. For example, use of an ESP will require 4 times the carbon to be injected for mercury/dioxin control than if a fabric filter is used. The capital cost for a fabric filter is higher than the capital cost for an ESP on the same boiler.

Response: See response for DCN EPA-HQ-OAR-2002-0058-3213.1, Excerpt Number 20.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-2702.1
Comment Excerpt Number: 8

Comment: CIBO/URS have estimated a PM control cost for coal, liquid, and gas 2 boilers and process heaters of $7 billion versus EPA's estimated PM control cost of $6.1 billion.

Response: See preamble for response.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-2702.1
Comment Excerpt Number: 9

Comment: EPA has estimated costs to install packed bed scrubbers for HCl control. Industrial boilers do not use packed bed scrubbers for acid gas control, as the limitations of these devices make them impractical for use on applications with high flow rates, high PM loading, and high inlet pollutant concentration. EPA's own fact sheet on these devices, located at http://www.epa.gov/ttn/catc/dir1/fpack.pdf, lists these limitations of these devices and indicates that they are only used in applications up to 75,000 scfm, which limits their use to small units only. Facilities will instead install wet scrubbers, dry scrubbers, or semi-dry scrubbers to control acid gas emissions from industrial boilers. EPA has estimated HCl control costs for equipment that industry is not likely to install.

CIBO/URS have estimated capital costs for coal, liquid, and gas 2 boilers and process heaters for HCl control of $9.3 billion, while EPA's capital cost estimate for wet scrubbers is $3.3 billion.

Response: See response for DCN EPA-HQ-OAR-2002-0058-3213.1, Excerpt Number 21.

Commenter Name: Henry T. Graham
Commenter Affiliation: Louisiana Chemical Association
Document Control Number: EPA-HQ-OAR-2002-0058-2731.1
Comment Excerpt Number: 10

Comment: EPA needs to consider all costs and burdens in the rule analyses and in the analyses required under other applicable laws and Executive Orders.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2867.1, Excerpt Number 15.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-2702.1
Comment Excerpt Number: 10

Comment: EPA presents several cost options in the two ERG memos. Option 2E assumes that facilities will not incur costs to comply with the dioxin/furan standards because they will test for dioxin/furan and be below detection levels. This is illogical, especially because EPA has not outlined in the rule any procedures for handling non-detects when performing compliance testing and there are boilers in the EPA emissions database with dioxin/furan emissions that are non-detect but actually measured emissions higher than the proposed limit. CIBO/URS has estimated carbon injection as the control measure for dioxin/furan emissions and mercury emissions. As stated above, our cost estimate for carbon injection for coal, liquid, and gas 2 boilers and process heaters is $1.7 billion versus EPA's of only $9.5 million.

In the event Work Practice Standards for Natural Gas fired boilers and process heaters are replaced with the numerical standards proposed in the preamble for Gas 1 boilers, the following costs were estimated using the same assumptions as above. We have assumed that gas 1 boilers and process heaters will apply the following technology: FF (for PM), carbon injection (for Hg and D/F), wet scrubber (for HCl), and CO catalyst. (See submittal for a table of costs for Gas 1 boilers).

The above estimates could be considered conservative since they assume that emission controls can be installed on existing units and that controls will actually allow compliance with the proposed emission limits. These are very conservative assumptions since it is known that retrofit of emissions control devices such as these is extremely difficult for some units due to design and space limitations, and major issues with the floor setting methodology make achievability of the emission limits highly uncertain. Therefore, it is likely that some combustion units will need to be replaced rather than retrofitting controls to those existing units. Replacement of combustion units could escalate these costs significantly.

Response: See preamble for response.

Commenter Name: Henry T. Graham
Commenter Affiliation: Louisiana Chemical Association
Document Control Number: EPA-HQ-OAR-2002-0058-2731.1
Comment Excerpt Number: 11

Comment: Retrofit control costs are underestimated and are not technically or economically feasible in many refinery locations due to a lack of plot space that meets required safety standards. Retrofit controls included in the EPA analysis have not all been demonstrated effective at the low emission limits proposed.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2699.1, Excerpt Number 11.

Commenter Name: W. Randall Rawson
Commenter Affiliation: American Boiler Manufacturers Association
Document Control Number: EPA-HQ-OAR-2002-0058-2698.1
Comment Excerpt Number: 14

Comment: Operation of oxidation catalyst for CO control would be subject to several design constraints. As an initial matter, oxidation catalyst performs optimally at temperatures of 600°F and above. Small boilers operating at turndown ratios may not be able to meet these temperatures. In particular, package boilers operating at low pressure and low load may experience low flue gas temperatures. [Footnote: The following represent typical outlet flue gas temperatures for package boilers:]
3 25% MCR 100% MCR
125 psig 3 pass FT
380F
460F
125 psig 4 pass FT
365F
400F
300 psig saturated IWT
454F
628F
750 psig 730F superheated IWT
559F
807FWhile an increase in volume and pressure drop may compensate for lower temperature, capital costs and operating expenses may increase. For example, a typical boiler producing 80,000 pounds of saturated steam is assumed to use a fan (at sea level) that moves 18,000 cfm at 14 inches of water column, and its energy consumption is 39.4 kw. The addition of a CO oxidation catalyst will add an estimated 2 inches water column to the draft losses of the system. This figure is based on typical design criteria, plus the need to compensate for low flue gas temperature. To the extent that the air moving equipment is capable of overcoming the added draft losses, the static pressure increase would result in a new energy usage of 45 kw, or 14%

increase. Other costs associated with the use of oxidation catalyst include the need for a near perfect flow distribution, which require flow straightening material or large amounts of catalyst material. The formation of sulfates is also a concern, because they may bond to the substrate of the oxidizing catalyst and create a potential for a sulfuric plume of SO_3, which may condense to form sulfuric acid. Further, in some field erected units, the installation of oxidation catalyst can reduce boiler heat exchange surface for lack of an adequate "window" for placement. Based on all of the above, oxidation catalysts may present technical and economic constraints that were not adequately evaluated by EPA. Further, even at optimal temperatures, use of an oxidation catalyst may not be sufficient to meet a 1 ppm emission level for CO. As an alternative, ABMA recommends a CO limit in the 5 ppm range where oxidation catalyst is used at optimal flue gas temperatures (>600°F).

Response: See preamble for response.

Commenter Name: William R. Ermatinger
Commenter Affiliation: Northrop Grumman
Document Control Number: EPA-HQ-OAR-2002-0058-2506.1
Comment Excerpt Number: 16

Comment: Because EPA did not consider the effect of CO minimization on operating efficiency, EPA did not adequately address the increased cost of boiler or process heater operation in its evaluation of tune-ups as a NEST-1AP work practice standard. Moreover, the proposed tune-up inspection requirements address fuel usage and combustion characteristics in a general sense only and do not relate to or affect HAP emissions in a known or predictable manner.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2702.1, Excerpt Number 106.

Commenter Name: William R. Ermatinger
Commenter Affiliation: Northrop Grumman
Document Control Number: EPA-HQ-OAR-2002-0058-2506.1
Comment Excerpt Number: 21

Comment: Neither chloride nor mercury are typically measured by suppliers of liquid fuels such as residual oil or distillate oil, and there are no known reasonable, proven or cost effective fuel treatment technologies capable of removing chloride and mercury from liquid fuels. Fuel costs will increase considerably as suppliers attempt to meet new fuel specifications by obtaining or blending fuels from alternate sources that have lower naturally occurring levels of chloride or mercury. It is highly likely that it will not be possible to obtain No. 6 fuel oil meeting ASTM specifications and containing chloride and mercury at the levels sufficient to ensure consistent compliance with the proposed Boiler MACT regulation, forcing the costly shutdown and replacement of many No. 6 fuel oil fired boilers, including those at NGSB. It does not appear that such costs were considered by EPA during its development of the proposed regulation.

Response: See preamble for response.

Commenter Name: Donald R. Schregardus
Commenter Affiliation: Department of Defense
Document Control Number: EPA-HQ-OAR-2002-0058-2763.1
Comment Excerpt Number: 34

Comment: EPA has significantly underestimated the annual costs for coal and liquid-fired boilers by not including operational and maintenance costs in the economic analysis.

The U.S. Air Force conducted an independent assessment of the cost of compliance related to the proposed rule. This assessment resulted in 605 existing U.S. Air Force boilers, firing natural gas, liquid fuels or coal, being regulated on major HAP sources with a capital cost of $133.8 million and an annual recurring cost of $44.6 million. Using 7% interest and a 15 -year life for the capital cost, the total annualized compliance cost would be $59.3 million. The extrapolated total annualized cost for DoD would be $208 million based on the number of major HAP sources owned by each military service or $243 million based on the number of military emission units listed for each military service in the 1997 ICCR database.

In Table 11 of the preamble, EPA estimated that the nationwide impact would be 27,202 existing units to be regulated at an annualized cost of $2.9 billion which includes fuel savings. On page 32037-32038 of the preamble, EPA states that "the total capital and annual costs include cost for control devices, work practices, testing and monitoring." It further states that "Table 11 of this preamble shows the capital and annual cost impacts for each category. Costs include testing and monitoring, but not for recordkeeping and reporting costs."

For existing coal units, the EPA estimated annual costs at $62.4 million for 578 units or a cost per coal-fired boiler of $108,000. In contrast, the U.S. Air Force's preliminary assessment of recurring annual costs at $11.7 million for 6 units or a cost per boiler of $1.95 million. This annual unit cost includes testing and monitoring along with required "maintenance and operations" costs. It appears that the annual costs appearing in Table 11 did not include operations and maintenance costs for emission controls, which are significant and are driven by the emission limits. The annual costs appear to be limited to only testing and monitoring. Operations and maintenance costs will be incurred for existing coal units in sustaining the required emissions control devises linked to this regulation. These costs should be reflected in Table 11.

For liquid fuel-fired boilers, the EPA estimated annual costs in Table 11 at $27.4 million per year for 826 units, or $33,000 per unit. In contrast, the U.S. Air Force's preliminary assessment of recurring annual costs at $ 57.6 million for 51 units or an annual recurring cost per boiler of $1.13 million. This annual unit cost includes testing and monitoring along with required "maintenance and operations" costs. It appears that the annual costs appearing in Table 11 for liquid fuel-fired boiler did not include annual operation and maintenance costs for emission controls which will be required to meet the carbon monoxide (CO) limit of 1 ppmdv.

The primary driver for the elevated annual recurring costs lies in meeting the emission limits for oil- and coal-fired boilers established in the proposed rule.

Reevaluate the economic impact of this NESHAP in Table 11 to account for the capital and annual recurring operations and maintenance costs for air pollution control equipment that will be required to meet the proposed emission limits.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2702.1, Excerpt Number 61.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-2702.1
Comment Excerpt Number: 61

Comment: For units larger than 100 MMBtu/hr, EPA explains that "the capital costs estimated for installing controls on these boilers and process heaters to comply with MACT limits for the five HAP groups is over $14 billion." 75 FR 32025. While CIBO agrees with EPA's decision to act under section 112(h), the $14 billion figure grossly underestimates the cost of add-on controls by excluding the monitoring and operating expenses associated with such equipment. Other industry groups filing comments on this proposal have estimated that the capital cost of add-on controls for natural gas-fired units in EPA's database alone would be upwards of $50 billion for the subcategory. In reality, this number is likely even higher given that EPA's database does not include all the natural gas units in the country that would be affected by this rule and this estimate assumed that controls can be installed and that they can actually achieve the emission limits contemplated by EPA. If replacement of the combustion units was required, costs would be even higher unless production was shut down, and that presents another whole set of negative economic impacts.

Response: See preamble for response.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-2702.1
Comment Excerpt Number: 106

Comment: CO Control Costs
EPA estimates 482 units will install CO catalysts to control CO emissions. It would be very difficult to retrofit CO catalysts to existing boilers and process heaters. It is also not assured that

such installation could actually achieve the emissions limits proposed. CIBO recommends that EPA re-evaluate the approach taken and the data used to account for actual achievability and costs. CIBO believes the actual retrofit cost for CO catalysts will be very high.

Due to the lack of widespread deployment of CO catalysts on industrial solid-fueled boilers, many boiler owners are likely to view this technology as inherently more risky than traditional in-furnace techniques to control CO. The most commonly employed and cost effective method reducing in-furnace CO formation would be to "de-tune" the furnace by removing low-NOx firing systems and installing 1960's vintage burner systems that produce very low CO. Many companies will view this as posing significantly less technological risk than CO catalysts, due to their widespread use in boilers. As has been long established in the industry, a generally inverse relationship exists between CO and NOx in a well-tuned boiler. However, many industrial boilers are already either obligated to meet a specific NOx emissions standard, or to optimize NOx to achieve compliance with NAAQS Ozone standards, or both. Therefore the net effect of this CO standard will be to drive companies to "de-tune" their furnaces to control CO, and retrofit capital intensive NOx reduction technologies (e.g. Selective Catalytic Reduction) to control the resultant increase in NOx. EPA's own literature (EPA/600/SR-01/087 January 2002) provides a capital cost estimate of $50-110 per kW. Because these cost impacts have not been factored into EPA's estimates of the costs for controlling CO, EPA's estimates are significantly low. EPA should revise its estimates of the cost to industry to reflect one of the least technologically risky, and therefore one of the most probable, responses of many companies to comply with this standard.

Response: See preamble for response.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 117

Comment: Since the proposed emission limits are unachievable simultaneously and under all operating conditions without add-on controls, all gas and liquid units subject to emission limits will have to install CO controls, rather than just a limited set as EPA assumed. Most, in addition to those identified in the Agency estimates, will also have to install PM, Hg and HCl controls to handle normal variability, since those limits also apply at all times. PM controls will be needed for every installation of oxidation catalyst, since the catalyst system generates PM2.5 emissions (sulfuric acid aerosol) in addition to each activated carbon Hg or dioxin control system. In Attachment F, we discuss the full range of control need engendered by this proposal.

On page C-6 of the RIA, it is reported that catalytic CO controls were only assumed for gas and liquid fired boilers and process heaters with baseline CO emissions above 1000 ppm. This is an unreasonable assumption. Essentially all boilers and process heaters will have to install catalytic CO controls, in order to meet the proposed CO limits at all times, while meeting the other applicable limits, particularly any applicable NOx limit. For the limited number of units that may be able to meet the proposed CO limits at all times without oxidation catalyst, Selective Catalytic Reduction (SCR) controls for NOx would be needed because low-CO operating conditions greatly increase NOx production. It is likely sources would opt for the CO controls in this case, rather than installing NOx SCR, since oxidation catalyst may help meet the dioxin/furan limit and oxidation catalyst, unlike SCR, does not generate ammonia emissions. Therefore, installation of CO oxidation catalyst on all gas- and liquid-fired units subject to emission limits is the basis we suggest be used in estimating the costs for this proposal.

Recommendation: Revise all cost and benefit analyses to assume CO oxidation catalyst and PM controls on all gas- and liquid-fired units subject to a CO emission limit and Hg and HCl controls on 94% of all units. Assume a reasonable percentage will need to be replaced in order to accommodate the controls. Include the costs and burdens associated with revising the existing boiler or process heater to accommodate the controls and the lost production associated with the outages needed to install the controls or replace units.

Response: See preamble for response.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-2702.1
Comment Excerpt Number: 215

Comment: Energy and Other Environmental Impacts.
Some facilities cannot discharge waste water from a wet scrubber. These facilities will have to install dry systems, which will likely raise the cost impacts of the rule.

Response: See preamble for response.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 252

Comment: The past 20+ years have been focused on the most efficient reduction of NOx emissions while maintaining reasonable levels of CO (50 to 400ppm). This has resulted in the use of techniques such as fuel and air staging which attempt to utilize the maximum extent of the boiler furnace volume available for combustion. This is particularly true for oil fuels, where fuel bound nitrogen accounts for the major portion of the NOx formation. Staged air combustion, either through burner design or in conjunction with separate air ports (i.e. NOx ports or Over Fire

Air) is one of the most effective methods of reducing the conversion of fuel bound nitrogen to NOx.

* Reducing CO to extremely low levels will require a shift away from these energy efficient techniques to methods that increase operating costs (i.e. higher FGR rates, back-end cleanup, etc.).

Response: See response for DCN EPA-HQ-OAR-2002-0058-2702.1, Excerpt Number 106.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 257

Comment: Even use of CO catalysts may not provide high enough DRE (>98%) to meet these limits. During low load operation, which has highest potential for high CO, outlet temperature drops making catalyst DRE drop dramatically.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2698.1, Excerpt Number 14.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 273

Comment: The petroleum and petrochemical industry operates several thousand gas-fired process heaters and boilers at refineries and petrochemical plants. The majority of these are “natural draft” design, meaning that mechanical means such as forced draft and/or induced draft fans are not used to induce gas flow. The gas flow is induced primarily by stack gas buoyancy, created by the difference in temperature and elevation between the stack gas and ambient combustion air, and to a lesser extent by entrainment induced by fuel pressure. The combustion air flow is regulated via manually-operated mechanical air registers located on each individual burner. A stack “draft” damper also may be used to control pressure differential between the ambient air and the stack to reduce the impact of cross winds or load swings on fuel-air balance. There is a wide variety of process heater designs depending on duty, with differences in heat input capacity, number of individual burners (from less than 10 to more than 100), firebox geometry (single furnace, dual furnace, cylindrical and rectangular geometry, aspect ratio, radiant heat transfer surface arrangement and placement), furnace exit temperature, burner type (radiant wall, jet, etc.), burner placement (bottom, side, top, combinations thereof), convective heat transfer surface arrangement, stack exhaust temperature, and other factors (e.g., Figure 12).

The furnace duty is especially critical as this establishes the combustion environment controlling CO and NOX emissions. Typically, the burners must deliver a precise range of radiant heat transfer to the furnace heat transfer surfaces to achieve the required fluid temperature for the process. This places limits on the range of variations in burner operating conditions for emissions tuning purposes.

In EPA's Regulatory Impact Analysis, MACT emission controls for HAPs include:
* CO: combustion controls and oxidation catalyst;
* Filterable PM: fabric filter or ESP;
* Mercury: activated carbon injection (ACI) plus fabric filter;
* Dioxins/furans: activated carbon injection plus fabric filter; and
* HCl: packed bed wet scrubber.

It is likely that most process heaters will not meet one or more of the proposed limits for Gas 2 or the prospective limits for Gas 1. These would need to install combinations of the emission control technologies described above. Figure 13 illustrates a typical vertical pipestill heater, a common design in the 40-80 MMBtu/hr capacity range. Figure 14 illustrates the same unit with all of the above MACT controls installed.

Assuming typical stack temperatures of 500-800 0F, the oxidation catalyst would be the first device because oxidation catalysts are more efficient at higher temperatures, minimizing the amount of catalyst required. Typical pressure drop across a catalyst unit and duct work routing the gas from the stack to the catalyst is 4 to 8 inches of water (representing much of the available pressure from natural draft).

The next device in line would the ACI system and fabric filter, comprised of a sorbent storage silo, feeder, compressor, spent sorbent storage silo, injectors, the fabric filter and utilities. In addition to reducing mercury and dioxins/furans, the fabric filter is needed to capture the particulate matter added as sorbent. The fabric filter is the largest physical component of the system, approximately the same physical volume as the process heater itself and greater. It is assumed that the dust (consisting mainly of spent sorbent) collected in the fabric filter would be transported to a waste disposal facility.

The gas temperature would need to be decreased prior to the ACI/fabric filter system (typically to 300 0F or lower) to facilitate mercury adsorption on the sorbent and to minimize potential dioxin/furan formation (which has been shown to occur at temperatures of approximately 300-800 0F if precursors are present). While this could be achieved with a water quench, this would be a wasteful use of water resources. An air preheater or waste heat boiler is typically the optimum engineering choice for reducing exhaust temperature. An air preheater would require construction of a new windbox to direct the heated air to the burners; in many cases this would be impractical due to burner arrangement. The air preheater (or waste heat boiler), fabric filter and associated ductwork would add perhaps another 8 to 12 inches of water pressure resistance to the gas path.

The wet gas scrubber for HCl removal would be next component in the gas path, comprised of the packed tower absorber, two to three tanks (caustic, recirculation and blowdown),

recirculating and caustic pumps, and make-up water supply. The packed tower absorber would be the largest physical equipment component, approximately the same size as the process heater or slightly smaller. The pressure drop across a packed bed scrubber and associated ductwork is typically in the range of 12 to 20 inches of water.
The addition of the above controls will require the addition of a new stack, since the existing integral stack above the process heater would be replaced by ductwork. Because of the low gas temperature leaving the scrubber, it is likely that the stack gas would need to be reheated to gain sufficient plume rise even with a taller stack. The energy for the stack gas reheat coils would typically be supplied as steam, and may represent a few percent of the total fuel energy consumed in the unit.

Because of the amount of pressure for inducing combustion air flow that is generated by natural draft is much less than that achievable with electrically-driven or steam-driven fans, any added flow resistance to the gas path becomes significant. Adding post-combustion emission controls typically must be accompanied by addition of forced draft and induced draft fans. This allows the absolute pressure within the system to be “balanced” to avoid over-pressure or under pressure in the unit that could lead to structural failure. It also allows a slight negative pressure to be maintained within the process heater and the emission control equipment for safety purposes (to prevent leakage of combustion gases around the equipment and consequent worker safety risks).

The physical size of the above emission controls requires 2 to 3 times the footprint of the process heater or boiler itself. In most refineries, the units are arranged tightly together (e.g., Figure 15). Existing space around process areas is designed to permit maintenance access (cranes, large vessel transport, etc.) and to provide safe distances between units and worker escape routes in the event of a safety hazard. This would require elevating the added equipment above the unit, with consequent requirements for large new foundations and extensive structural steel. Elevating the equipment adds significantly to the overall cost of the retrofit, perhaps 2 to 5 times that of the basic equipment installation itself when all preliminary and detailed engineering and construction costs are factored in. The costs would be much greater than EPA‘s estimates given in the RIA, which typically used retrofit factors of 1.2 to 1.4. In many retrofit cases, the overall cost is likely to be so great, or otherwise infeasible due to space constraints or other engineering issues, that it is more cost-effective to completely replace the unit. When this scenario is multiplied by the typical 40 to 60 process heaters in a major refinery, the total impact would be enormous.

Response: See preamble for response.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 275

Comment: A summary of the potential capital costs associated with upgrades necessary to comply with the alternative numerical MACT floor limits, including a comparison to EPA's estimates, is provided below: [See Table 11. Comparison of EPA and API Total Installed Capital Cost (CI) Estimates ($)]

API's total estimated cost for pollution control upgrades for Gas 1 sources is approximately $39.7 billion versus EPA's estimate of $20.9 billion, a 90 percent difference. It should be noted that API estimates are likely on the low side due to the potential underestimate of the number of affected units in EPA's database and the likely exclusion of potentially major costs that are impossible to reliably estimate at this time. While EPA's capital and operating cost estimates were generally reasonable for units requiring control device upgrades to fabric filters, wet scrubbers, catalytic oxidation and activated carbon, it is believed that EPA grossly underestimated the number of units that would be required to install catalytic oxidation and mercury/dioxin furan controls leading to a significant underestimate of costs by EPA.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2960.1, Excerpt Number 275.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 281

Comment: API's total estimated costs for pollution control upgrades for Gas 2 sources is approximately $2.6 billion versus EPA's estimate of $1.6 billion, a 64 percent difference. It should be noted that API estimates are likely on the low side due to the potential underestimate of the number of affected units in EPA's database and the likely exclusion of potentially major costs that are impossible to reliably estimate at this time. While EPA's capital and operating cost estimates were generally reasonable for units requiring control device upgrades to fabric filters, wet scrubbers, catalytic oxidation and activated carbon, it is believed that EPA grossly underestimated the number of units that would be required to install catalytic oxidation and mercury/dioxin furan controls leading to a significant underestimate of costs by EPA.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2960.1, Excerpt Number 275.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 283

Comment: UNDERESTIMATED POPULATIONS OF GAS 1 AND GAS 2 UNITS

National annual cost impacts discussed in this report are based on statistics provided by EPA pursuant to the 2008 Boiler Survey, which indicated that 11,532 Gas 1 and 199 Gas 2 BPHs would be impacted by the proposed rule. However, EPA reported in the proposed NESHAP for the vacated BPH NESHAP promulgated in 2003 that a total of 46,982 Gas BPHs would be affected. The reason for the 4-fold decrease in the estimated number of existing affected units in the BPH Source Category is unclear and has not been recognized by EPA in the supporting documentation related to the development of the proposed rule. If EPA has indeed underestimated the number of Gas 1 and Gas 2 units that will be impacted by the recently proposed BPH NESHAP by a factor of 4, the cost impact estimates developed by both EPA and API that are discussed in this report are also 4 times lower than the actual cost impacts.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2960.1, Excerpt Number 275.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 284

Comment: REPLACEMENT OF BHPS

It is likely that a significant number of existing BPHs that would be affected by the BPH NESHAP are structurally designed and/or situated such that installation of extensive control technologies and associated equipment on those BHPs is infeasible. In such cases, it is expected that compliance with the proposed rule would require installation of new replacement BHPs with different structural design or in a more feasible location to allow connection with air pollution controls. Likewise, the potential impacts of extended outages with existing BPH modifications to facilitate installation of control equipment could necessitate the replacement of BPHs in order to reduce production downtime and outages during construction/commissioning. Obviously, the cost impacts of the BPH NESHAP on any facility requiring replacement units could be devastating, and if any appreciable fraction of the entire population of units is replaced, the total Subcategory-wide impacts would be enormous.

Based on limited data provided by several API member companies, the average total installed cost of replacing a 250 mm Btu/hr boiler and process heater is roughly $29.3 million and $31.5 million, respectively. The number of Gas 1 and Gas 2 units that might need to be replaced to accommodate the new pollution control equipment is unknown; however, one API member indicated that up to 50 percent of such units might need to be replaced.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2699.1, Excerpt Number 11.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 287

Comment: Catalytic oxidation controls were assumed to only be required if a unit's baseline emissions exceeded 1000 ppm of CO, resulting in a very small percentage of units requiring catalytic oxidation controls. EPA provided no scientific basis or reasoning to support the logic that tune-ups and replacement burners alone could meet the proposed emissions limits.

With respect to CO, it seems implausible that tune-ups and burner replacements alone will enable virtually all emissions units to comply with the proposed limits during all operations (even during startup and shutdown) with no increase in energy consumption, NOx emissions, or other regulated pollutant emissions. Although it may be possible that some units not achieving the MACT Floor could comply through implementation of these relatively minor adjustments, extensive study would be required to determine the wide-spread feasibility of achieving the MACT Floors with tune-ups and/or burner replacements.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2960.1, Excerpt Number 117.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 288

Comment: For mercury and dioxin/furan controls, EPA assumed that activated carbon injection (ACI) would be required if (in EPA's estimation) additional controls were necessary after any primary particulate matter and hydrogen chloride control upgrades were installed. The explanation of logic provided by EPA is vague and does not seem to harmonize with EPA's ultimate conclusion that only about 10 percent of units would require ACI.
Similarly, EPA's estimate that only a small percentage of units (roughly 1 percent) would require ACI controls does not seem plausible and was not supported in EPA's documentation. In the absence of scientific data supporting EPA's assumptions and drawing a direct correlation to Gas 1 and Gas 2 units, is seems more appropriate to assume that up to 94 percent of emissions units would be required to install add-on controls for abatement of CO and mercury/dioxin/furan.

Response: See response for DCN EPA-HQ-OAR-2002-0058-3213.1, Excerpt Number 19.

Commenter Name: Matthew Todd and David Friedman

Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 289

Comment: CATALYTIC OXIDATION COSTS
Catalytic oxidation controls would most appropriately be located downstream of heat exchangers. The state-of-the-art control technology for catalytic oxidation in this environment is a system known as "regenerative catalytic oxidation (RCO)" manufactured by Babcock Power, which utilizes a proprietary catalyst to achieve necessary oxidation temperatures with nominal reheat. Trinity used a publicly available permit application reviewing this technology to develop a cost basis for this control strategy, which is included in Appendix A (Table A-1). [Appendix A (Table A-1) of the submittal].

Capital costs and capital recovery were estimated for individual affected units in EPA's database using the widely accepted 0.6 exponential scaling factor, which incorporates the economies of scale of equipment of different sizes, applied to information in EPA's Gas 1 and Gas 2 databases. Other annual operating costs were established based on the linear ratio of equipment sizes, operating hours and a capacity factor of 90 percent during actual hours of operation.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2698.1, Excerpt Number 14.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 290

Comment: ACTIVATED CARBON INJECTION COSTS
ACI capital costs were developed for a 250 MMBtu/hr base unit using information provided by ADA Environmental Solutions, a leading activated carbon manufacturer and control system provider. Operating costs were estimating EPA cost methodologies, ADA having confirmed the reasonableness of carbon usage estimates, which comprise the majority of operating costs. A detailed cost breakout is provided in Appendix A (Table A-2). [See submittal for Appendix A's Table A-2.}
Capital and operating costs were estimated in the same manner as discussed for catalytic oxidation.

[See submittal for TABLE 2-1. TOTAL INSTALLED CAPITAL AND ANNUALIZED COSTS FOR POLLUTION CONTROLS ($/250 MMBTU/HR UNIT)]

Response: The EPA thanks you for your information.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 291

Comment: Summaries of API and EPA total capital cost estimates for the Gas 1 and Gas 2 subcategories are provided in Table 2-2. [See submittal for Table 2-2 Comparison of EPA and API Installed Capital Cost (TCI) Estimates ($).]As shown, API cost estimates are assumed to be equal to EPA's estimates for fabric filter and wet scrubber controls. API cost estimates indicate that catalytic oxidation and activated carbon injection costs are drastically underestimated, as are total capital costs for all control technology upgrades.

Summaries of API and EPA total annual cost estimates for the Gas 1 and Gas 2 subcategories are provided in Table 2-3. [See submittal for Table 2-3 Comparison of EPA and API Installed Capital Cost (TCI) Estimates ($).]As shown, API cost estimates are assumed to be equal to EPA's estimates for fabric filter and wet scrubber controls. API cost estimates indicate that catalytic oxidation and activated carbon injection costs are drastically underestimated, as are total annual costs for all control technology upgrades.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2960.1, Excerpt Number 275.

Commenter Name: Henry T. Graham
Commenter Affiliation: Louisiana Chemical Association
Document Control Number: EPA-HQ-OAR-2002-0058-2731.1
Comment Excerpt Number: 12

Comment: EPA has severely underestimated the number of units affected by the control requirements and has therefore underestimated the negative impact of this proposal on the economy and on jobs.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2960.1, Excerpt Number 117.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 100

Comment: Use of non-representative data, use of a faulty methodology, failure to consider unit and operating variability, and failure to consider achievability has led to development of emission limit proposals for gas- and liquid-fired boilers and process heaters that are significantly more stringent than reasonable. As a result, many boilers and process heaters and their associated processes will be shutdown and jobs will be lost.

Response: See response for DCN EPA-HQ-OAR-2002-0058-1876, Excerpt Number 3.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 118

Comment: A significant percent of units will be unable to add controls to the existing unit because of space or structural constraints and thus new units will need to be constructed at greatly increased cost. The RIA estimates included no costs or burdens for replacement units or for installing NOx or CO controls on most Gas 2 and liquid fired units. Additionally, no costs were included for lost production while the boiler or process heater was being replaced or for the costs associated with such replacement units having to meet new source standards rather than existing source standards. Where the outage and/or cost associated with trying to meet these limits are excessive or the proposed limits cannot be achieved by any means, the units and their associated processes will be shutdown and jobs lost. The impact of lost jobs and economic activity is not reflected anywhere in the record.

Recommendation: Revise impact analyses to reflect that a significant percentage of sources and their associated processes will be shutdown and to reflect the resulting job losses.

Response: ******Cost Issue
The EPA used a standard market analysis to analyze the proposed MACT standards. The approach uses a single period multimarket partial equilibrium model to compare pre-policy market baselines with expected post-policy market outcomes. The analysis' time horizon is the intermediate run; some production factors are fixed and some are variable and is distinguished from the very short run where all factors are fixed and producers cannot adjust inputs or outputs. The intermediate time horizon allows us to capture important transitory stakeholder outcomes. Key measures in this analysis include industry-level changes in price levels, production and consumption, jobs, international trade, and social costs (changes in producer and consumer surplus). This analysis was done on the national level for many reasons. Impacts on price level, international trade, national production, and jobs could not have been estimated if the analysis focussed on regional or state levels. EPA also does not have the necessary data to estimate impacts on individual states. Even if EPA had the data a detailed estimate of individual state and industry responses would be beyond the scope of what could be accomplished for this analysis.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 144

Comment: There is no evidence that the controls EPA has identified work for gas-fired equipment or for boilers and process heaters firing all types of liquid fuels for all of the 5 classes of pollutants proposed for regulation. Nor is it demonstrated that estimates based on controls used for liquid- or solid-fired equipment are scalable to gas-fired units. As we have stated, it appears all possible controls will have to be installed on all units subject to numerical emission limits in order to try to meet the proposed limits at all times. Even then, it is not clear that compliance can be achieved and many units and their associated processes will have to shutdown to avoid non-compliance. In many other cases, the costs and burdens associated with this large and complex set of controls will be unsupportable, also resulting in process shutdowns and job losses.

We discuss the required controls in detail in Attachment F. Our following comments summarize some of the Attachment F information and expand upon it.

Response: See response for DCN EPA-HQ-OAR-2002-0058-1779, Excerpt Number 78.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 218

Comment: On pages 32038 and 9 of the preamble, EPA discusses their analysis of the impact of this proposal on jobs. While the analysis appears robust, it is not, because it assumes all sources will be able to meet the proposed emission limits and because it uses the EPA estimates for the costs and burdens of compliance, which we have shown throughout these comments to be grossly underestimated.

One factor of specific importance that has not been addressed in detail in the Trinity report is the need to replace a particular boiler or process heater, in order to add the required controls. It takes a detailed engineering evaluation to determine where replacement is required, but we believe there will be many situations where a particular boiler cannot accommodate the add-on controls required for compliance. This can occur because 1) there is inadequate space for adding the additional equipment, 2) the furnace structure and foundations cannot accommodate the added equipment, or 3) the business cannot accept the extensive process outage associated with retrofitting the unit.

Space is a concern, particularly for process heaters, because these heaters by their nature are located close to the process equipment they serve. Thus, there is often little room to safely add fans and blower, catalyst beds, activated carbon facilities and provide for adequate space to service that equipment. Additionally, many process heaters have floor burners and in those cases, it is often impossible to add forced combustion air systems because of inadequate space for the ductwork under the heater. At significantly added cost, some of the space problem can be offset by building the controls vertically. However, the existing boiler or process heater structure and foundations often cannot accept the additional weight and wind load and adding foundations and structure adjoining the existing unit can put it at risk from the vibrations and construction activity. Converting a natural draft unit to induced draft, adding forced combustion air systems and changing out burners, which will be necessary in addition to the add on controls because of the addition of the forced combustion air system, will require long process heater and thus process outages, which often cannot be tolerated.

We believe these concerns will lead to replacement of many process heaters and some boilers. While it is difficult to generalize, Trinity estimates that replacing a 250 MMBTU/hr boiler or process heater in order to accommodate the required add-on controls will triple the cost versus retrofitting an existing boiler or process heater. Since this will be a common occurrence, the impact on the cost and burdens associated with this proposal will be extensive.

Recommendation: The jobs and national impacts analyses should be redone, assuming a significant percentage of gas- and oil-fired boilers and process heaters subject to these emission limits will be unable to meet those limits and that a significant percentage will have to be replaced in order to meet the proposal, using realistic estimates of the number of impacted boilers and process heaters in each subcategory units, and including all of the costs identified in these comments, not just a subset of costs as included in EPA estimates.

Response: See response for DCN EPA-HQ-OAR-2002-0058-1779, Excerpt Number 78.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 285

Comment: LOST PRODUCTION

There are numerous possible scenarios in which installation and operation of the control technologies that would be required to comply with numerical limits would result in atypical downtime that cannot be fully quantified due to the uniqueness of each process. Control device operational issues that could lead to interruptions in plant production might include the following:
* Unit downtime due to initial construction/commissioning of pollution control systems (e.g., process cannot operate normally during process of adaption of new control equipment)

* Unit downtime due to control device operational issues (control device malfunctions or requires unscheduled maintenance)
* Unit downtime due to required/scheduled control device maintenance (which may be extended for events that do not go as planned or where start up does not occur smoothly after maintenance is completed)
* Production outages can have major economic ramifications and should not be ignored, even though these impacts cannot be fully quantified at this time.

Response: See preamble for response.

Commenter Name: S. Lewis Ebert
Commenter Affiliation: North Carolina Chamber
Document Control Number: EPA-HQ-OAR-2002-0058-2890.1
Comment Excerpt Number: 1

Comment: The Boiler MACT rule will require installation of up to five different air pollution control devices that will conflict with current control requirements that the majority of boilers already use to control for key pollutants.

Response: See preamble for response.

Commenter Name: Williams Wicks
Commenter Affiliation: Packaging Corp
Document Control Number: EPA-HQ-OAR-2002-0058-3130
Comment Excerpt Number: 2

Comment: We estimate a cost of $30 million to install the required control measures in the plant I work in! The benefits of the Boiler MACT standard will be of dubious value to health or environmental protection. US boilers are already operate with efficient pollution abatement equipment and discharge at very low rates per unit output. The cost : benefit of the standard will be great. I am very skeptical of EPA’s published estimates of compliance costs at $9.5 billion. The wood products and pulp and paper industries alone are estimating a compliance cost of at least $6 billion.

Response: See response for DCN EPA-HQ-OAR-2002-0058-0856.1, Excerpt Number 2.

Commenter Name: Kari Frantom
Commenter Affiliation: Graphic Packaging
Document Control Number: EPA-HQ-OAR-2002-0058-3142
Comment Excerpt Number: 2

Comment: Achievement of the limits dictated by the Boiler MACT rule will require installation of different air pollution control devices that will impose tens of billions of dollars in unnecessary capital costs. [Footnote: Cost, job loss and other data provided by the American Forest and Paper Association]

Response: See response for DCN EPA-HQ-OAR-2002-0058-0856.1, Excerpt Number 2.

Commenter Name: Steve Smith
Commenter Affiliation: LyondellBasell Industries
Document Control Number: EPA-HQ-OAR-2002-0058-3118.1
Comment Excerpt Number: 4

Comment: The cost and benefit estimates and economic and regulatory analyses should be updated to reflect the underestimates of costs and overestimates of benefits in the current proposal and the actual impact the proposal on jobs and the economy. Among the major corrections needed are the following.

Retrofit control costs are underestimated and control retrofits are not technically or economically feasible in many locations due to a lack of plot space that meets required safety standards. Many units will require total replacement, if that proves economically viable.

Controls included in the EPA analysis have not been demonstrated to be effective at the low emission limits proposed for clean burning fuels (.e.g. gases and light liquids).

EPA has underestimated the number of boilers and process heaters affected by the proposed control requirements. There are many more Gas-2 and liquid-fired units than EPA estimates.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2699.1, Excerpt Number 11.

Commenter Name: John Hopewell
Commenter Affiliation: American Coatings Association
Document Control Number: EPA-HQ-OAR-2002-0058-2886.1
Comment Excerpt Number: 7

Comment: EPA has underestimated the cost of boiler MACT.
Revisions are needed to reduce the cost of boiler MACT.

Response: See response for DCN EPA-HQ-OAR-2002-0058-3213.1, Excerpt Number 7.

Commenter Name: Sonnichsen Engineering, LLC
Commenter Affiliation: Tim W. Sonnichsen
Document Control Number: EPA-HQ-OAR-2002-0058-2931.1
Comment Excerpt Number: 10

Comment: The economic effects on boilers located in Major HAP's Sources would be significantly greater due to the larger number of pollutants to be controlled. In this case, the rule provides better estimates the capital and annualized costs of equipment. Table 9 presents EPA's estimates. The existing 239 biomass units are projected to spend an average of $5.2 million dollars per unit on capital investments. This will add approximately $1.3 million dollars to the annual operating costs of the facility. In many instances, this will challenge the economic viability of the facility.

Response: See response for DCN EPA-HQ-OAR-2002-0058-0856.1, Excerpt Number 2.

Commenter Name: Sonnichsen Engineering, LLC
Commenter Affiliation: Tim W. Sonnichsen
Document Control Number: EPA-HQ-OAR-2002-0058-2931.1
Comment Excerpt Number: 11

Comment: I understand that several representatives of the wood-products industry, other owners and operators of biomass boilers, and several other industrial trade groups will provide comments on the MACT rules. Some will include the cost impacts to their facilities. Kindly consider their projections of the costs for achieving these MACT standards as real. (I helped prepare some of these estimates and can assure the EPA that they are, if anything, conservatively low for the retrofit of control technologies.)

Response: See response for DCN EPA-HQ-OAR-2002-0058-0856.1, Excerpt Number 2.

Commenter Name: Russ A. Wozniak
Commenter Affiliation: Dow Chemical Company
Document Control Number: EPA-HQ-OAR-2002-0058-2632.1
Comment Excerpt Number: 65

Comment: Dow owns and operates one coal-fueled boiler at an existing major stationary source and thus is directly impacted by EPA's proposed rule. EPA has proposed emission limits for Hydrogen Chloride (HCl), Mercury, Carbon Monoxide, and Dioxin/Furan that may be unachievable and not measurable even if all known emission controls are installed at our existing facility. Dow estimates that our capital costs to install the anticipated necessary control equipment is in excess of $30,000,000 (based on EPA cost models with adjustments) and that our ability to meet the proposed emission limits for HCl and other pollutants remains in question due in part to the variable nature of the chlorine content of various coals that are combusted in our facility. Coal quality data from a three month period between February 4, 2010 and May 7, 2010 shows that the chlorine content varies from 0.14 to 0.4 wt%. Dow comments that the very high capital retrofit cost along with an element of uncertainty with respect to meeting the proposed emission limits is unreasonable, and will jeopardize the long-term viability of our coal-fueled source should this rule be finalized as proposed.

Response: See response for DCN EPA-HQ-OAR-2002-0058-1779, Excerpt Number 78.

Commenter Name: Patrick Strauch
Commenter Affiliation: Maine Forest Products Council
Document Control Number: EPA-HQ-OAR-2002-0058-3120.1
Comment Excerpt Number: 3

Comment: However, is the fact that meeting this rule could require several new monitoring and filter technologies, which some people have predicted could cost the industry over $7 billion dollars. This type of cost burden should only be seen as a disadvantage in the global marketplace.

Response: See response for DCN EPA-HQ-OAR-2002-0058-1876, Excerpt Number 3.

Commenter Name: Mike T.W. Carey
Commenter Affiliation: Ohio Coal Association
Document Control Number: EPA-HQ-OAR-2002-0058-2878.1
Comment Excerpt Number: 3

Comment: U.S. EPA acknowledges the significant impact and cost of these Proposed Rules on a substantial number of entities, yet persists in these oppressive and burdensome regulations. 75 Fed. Reg. 32006, 32044-32045. U.S. EPA's abject refusal to consider the challenges and costs of the Proposed Rules contravene the agency's obligation to consider compliance costs and regulatory alternatives with respect to entities and effectively require the sunsetting of many small and medium sized boilers.

Response: See response for DCN EPA-HQ-OAR-2002-0058-1876, Excerpt Number 3.

Commenter Name: Leslie Sue Ritts
Commenter Affiliation: National Environmental Development Association's Clean Air Project NEDA/CAP
Document Control Number: EPA-HQ-OAR-2002-0058-2794.1
Comment Excerpt Number: 13

Comment: The Regulatory Impact Analysis Fails to Account for Cost of Retrofitting The Industrial Fleet of Boilers.

The Regulatory Impact Analysis (RIA) for this rulemaking provides an overly rosy picture of the ability of many American manufacturers to accommodate the costs of retrofitting the fleet of existing boilers to meet the proposed standards for existing sources. Boilers in many industry sectors are aging and it will not be feasible or cost-effective to retrofit these boilers to comply with the rule, necessitating their shutdown, and for the facilities that can afford it, their replacement. EPA has not evaluated this trend in its RIA. There is a body of readily available information about the decline of American industry within other federal governmental bodies and we submit that it would be arbitrary and capricious for EPA to ignore this body of information.

Response: See response for DCN EPA-HQ-OAR-2002-0058-1779, Excerpt Number 78.

Commenter Name: Jennifer Klein
Commenter Affiliation: Ohio Chamber of Commerce
Document Control Number: EPA-HQ-OAR-2002-0058-2901.1
Comment Excerpt Number: 1

Comment: Although EPA's estimates indicate that the total capital cost will be $9.5 billion, AF&PA has estimated that the total capital cost of the rule will be over $20 billion. Based on AF&PA's review, EPA used incomplete and old data or information to derive their cost estimates. In addition, many of EPA's assumptions are not based on real world applications. Below are a few items that clearly show why EPA's cost analysis is grossly inaccurate.

EPA used the outdated Control Cost Manual and AF&PA based their cost estimates on more recent information, including actual vendor cost estimates, actual project costs, BACT and BART analyses, industry control cost studies, etc.

AF&PA used a CO catalyst cost 4 times higher than EPA's. AF&PA's is based on a recent quote from BASF and EPA's is based on the 1998 Control Cost Manual section on catalytic oxidizers for VOC control.

AF&PA's CO control capital costs are $1.2 billion for liquid and gas 2 and $1.5 billion for coal and biomass, where EPA's total estimate for CO control capital costs is only 13.9 million, mostly because they have assumed that tune-ups and replacement burners will be adequate for the vast majority of boilers to comply.

EPA has estimated that activated carbon injection will only be required on 155 existing boilers because installation of a fabric filter is expected to achieve the mercury emission limits, except in cases where a unit already has a fabric filter and does not meet the limits. AF&PA does not agree that fabric filters will be sufficient to reduce mercury emissions to the ultra low levels proposed in this rule. EPA's estimated industry-wide capital cost for activated carbon injection is only $9.5

million. AF&PA estimates for carbon injection required for mercury and dioxin/furan control is $1.7 billion.

AF&PA has estimated a PM control cost of $7 billion versus EPA's estimated PM control cost of $6.1 billion.

AF&PA has estimated capital costs for HC1 control of $9.3 billion, while EPA's capital cost estimate for wet scrubbers is $3.3 billion.

Response: See preamble for response.

Commenter Name: Dean C. DeLorey
Commenter Affiliation: The Amalgamated Sugar Company
Document Control Number: EPA-HQ-OAR-2002-0058-2833.1
Comment Excerpt Number: 1

Comment: The proposed Boiler MACT requirements are extremely concerning due to the significant costs required to ensure compliance. The rules will likely require the installation of very costly emissions control equipment or fuel switching. The excessive costs are unwarranted due to the small projected net decrease in HAP's emissions as a result of these proposed requirements.

Response: See response for DCN EPA-HQ-OAR-2002-0058-1876, Excerpt Number 3.

Commenter Name: James Johnson
Commenter Affiliation: U.S. Beet Sugar Association
Document Control Number: EPA-HQ-OAR-2002-0058-2827.1
Comment Excerpt Number: 2

Comment: Significant cost will also be incurred in advance of the rule applicability dates to determine compliance options and strategy.

Response: See preamble for response.

Commenter Name: Christopher S. Colman
Commenter Affiliation: Hovensa LLC
Document Control Number: EPA-HQ-OAR-2002-0058-2863.1
Comment Excerpt Number: 2

Comment: HOVENSA believes this rule will have devastating economic consequences for their refinery. Our preliminary estimate of capital costs alone to retrofit 23 oil fired units with emission controls is , with an additional capital for monitoring equipment and a annual operating cost to switch form residual fuel oil to distillate. (dollar amounts were reported as CBI)

Response: See response for DCN EPA-HQ-OAR-2002-0058-2506.1, Excerpt Number 21.

Commenter Name: Sarah E. Amick
Commenter Affiliation: Rubber Manufacturers Association
Document Control Number: EPA-HQ-OAR-2002-0058-2941.1
Comment Excerpt Number: 2

Comment: In a calendar year, RMA members may use more than 10% liquid fuel during periods of curtailment, or as a back up fuel for natural gas. As a result, under the proposal, boilers at RMA member facilities would be classified as liquid fuel boilers. Liquid fuel boilers would be required to install costly add on controls to meet the liquid fuel emission limits under the proposed rule. RMA estimates that if classified as liquid fuel boilers, add-on controls (assuming the following spray dry absorbent with fabric filter, carbon injection, and oxidation catalyst (CATOX) control technologies would all be required) for RMA tire member's 56 major source boilers would cost a total of approximately $571 million dollars. Because this cost estimate does not include costs for emission monitoring and data logging systems, compliance testing, and operating and maintenance costs associated with the controls, we believe the total cost including monitoring and maintenance costs would be significantly greater than the $571 million for add-on controls.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2702.1, Excerpt Number 61.

Commenter Name: Dan F. Hunter
Commenter Affiliation: ConocoPhillips Company
Document Control Number: EPA-HQ-OAR-2002-0058-2867.1
Comment Excerpt Number: 3

Comment: We believe EPA costs associated with the proposal are grossly underestimated, particularly since targeted controls have not been demonstrated to assure compliance with the proposal.

Response: See response for DCN EPA-HQ-OAR-2002-0058-1779, Excerpt Number 78.

Commenter Name: Michael Potter
Commenter Affiliation: Goodyear Tire and Rubber Company

Document Control Number: EPA-HQ-OAR-2002-0058-3181
Comment Excerpt Number: 4

Comment: Goodyear currently has sixteen natural gas boilers with backup capability to burn fuel oil located at tire plants that are major sources of HAP emissions, and that would be subject to the proposed standards. In addition Goodyear has several boilers with liquid fuel capability at chemical plants and at HAP area source plants. The sixteen tire plant boilers with backup oil capability range in size from 75 million Btu per hour heat input to 190 million Btu per hour heat input. Although Goodyear is not sure that technology exists to simultaneously meet proposed oil subcategory emission standards for all regulated pollutants on a reliable basis, Goodyear has attempted to estimate the capital costs that would be required to meet oil subcategory standards should backup fuels be needed for more than 10 percent of annual fuel input.

Assuming the following spray dry absorbent with fabric filter, carbon injection, and oxidation catalyst (CATOX) control technologies would all be required, Goodyear estimates the capital cost would average about $12 million per boiler, or about $192 million just to preserve the ability to use backup fuels for extended periods in Goodyear's boilers currently equipped with backup fuel capability in the five Goodyear tire plants that are major HAP sources. These estimates do not include costs for emission monitoring and data logging systems or for compliance testing, nor do they include operating and maintenance costs associated with the controls, which are unknown but Goodyear anticipates would be substantial. Costs for Goodyear's chemical plants have not been estimated.

Goodyear believes this cost would be unreasonable and warrants reconsideration of the proposed regulations as otherwise described herein.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2702.1, Excerpt Number 61.

Commenter Name: Bruce A. Steiner
Commenter Affiliation: American Coke and Coal Chemicals Institute
Document Control Number: EPA-HQ-OAR-2002-0058-2849.1
Comment Excerpt Number: 5

Comment: The economic analysis is clear. The Proposed Rule sets numeric emission limits for five pollutants (PM, HCl, Hg, dioxin/furans, and CO). At this time, coke oven gas-fired units are not controlled for these compounds. Using EPA's projected cost of control (annualized capital cost plus annual operating cost) for each pollutant, including monitoring, recordkeeping and reporting, an ACCCI member company has calculated an annualized cost of control of $8.6 million for a single 650 MMBTU/hr combusting coke oven gas. At a cost of $5/MMBTU for natural gas, it is economically unreasonable for the boiler operator to use coke oven gas to displace the first 1,720,000 MMBTU per year of natural gas in this boiler and the coke oven gas would be flared. The use of natural gas to replace coke oven gas in this situation would be to the detriment of the environment and our energy policies.

The constraint on available capital is an additional impediment to the installation of emission control equipment because increased natural gas consumption does not require a capital investment. Before a company will invest $8.6 million in annualized control costs for a single boiler, it will need to justify a return on the capital investment far greater than $8.6 million per year in displaced natural gas. Moreover, as discussed below, there is no expectation that expenditures of this magnitude will be sufficient to meet the proposed Gas 2 subcategory emission limits.
[Footnote 1: the capital cost for the unit is $27,747,000 and the annual non-capital cost is $5,678,000.]

Response: See response for DCN EPA-HQ-OAR-2002-0058-2960.1, Excerpt Number 275.

Commenter Name: David O'Keefe
Commenter Affiliation: USEC, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-3122
Comment Excerpt Number: 6

Comment: MACT costs. It is believed the costs of the proposal are greatly underestimated and do not take into account the man power requirements for implementation of the requirements. Increased costs are not only due to pollution control requirements, but also continued record keeping activities, development of plans and submittal of such plans, communication, and implementation. The costs of increased greenhouse gases and effect on the environment has not been fully captured, e.g., no beneficial reuse of coal fly ash, increased power generation for pollution control equipment, increased water utilization and wastewater processing, and disposal of combustion by products and increased NO, emissions to meet the CO emission limit.
It will likely require at least two and possibly three emissions control devices on each boiler to pass the five emissions limits. At a minimum, it appears that a bag-house and a scrubber will be required and likely charcoal injection.
USEC fully supports API’s and NPRA’s contention that the costs and burdens of the proposed new rule will be many times those estimated.
- Essentially all boilers and process heaters would have to install
extensive controls, which would require outright replacement of the boiler or process heater in many cases due to I) lack of space for required controls at current location, or 2) potential structural issues with existing unit.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2699.1, Excerpt Number 11.

Commenter Name: Lynn D. Westfall
Commenter Affiliation: Tesoro Companies
Document Control Number: EPA-HQ-OAR-2002-0058-2846.1
Comment Excerpt Number: 6

Comment: Even if it were feasible to physically place required emission control equipment at existing boilers and process heaters, the cost to install and operate the control equipment would be prohibitive. Based on an analysis of published equipment installations and our site-specific knowledge of construction costs in Hawaii, Tesoro's assessment of the likely cost to install and operate the control equipment configurations identified above on a typical 100 MM Btu/hr process heater at its Kapolei Refinery is:

Scenario #1:
Capital equipment and installation: $4 million
Annual operating cost: $1.5 million

Scenario #2:
Capital equipment and installation: $6.5 million
Annual operating cost: $1.4 million

Accordingly, to control the existing boiler and process heaters at the Kapolei Refinery we estimate that a capital cost of approximately $44 to $72 million would be incurred, along with annual operating expenses of approximately $17 million.

Current and reasonably-anticipated future economic conditions would probably not allow Tesoro to make this capital investment and sustain the recurring increase to the refinery's operating expenses.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2702.1, Excerpt Number 61.

Commenter Name: Deb Hastings
Commenter Affiliation: Texas Oil and Gas Association
Document Control Number: EPA-HQ-OAR-2002-0058-2857.1
Comment Excerpt Number: 11

Comment: EPA needs to consider all costs and burdens in the rule analyses and in the analyses required under other applicable laws and Executive Orders.
Retrofit control costs are underestimated and are not technically or economically feasible in many refinery locations due to a lack of plot space that meets required safety standards. Retrofit controls included in the EPA analysis have not all been demonstrated effective at the low emission limits proposed.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2867.1, Excerpt Number 15.

Commenter Name: Richard Krock
Commenter Affiliation: The Vinyl Institute
Document Control Number: EPA-HQ-OAR-2002-0058-2944.1

Comment Excerpt Number: 14

Comment: VI member companies are very concerned that the proposed requirements are overly burdensome and will require substantial financial expenditures at levels higher than those estimated by EPA, with minimal HAP reductions.

Response: See response for DCN EPA-HQ-OAR-2002-0058-1876, Excerpt Number 3.

Commenter Name: Dan F. Hunter
Commenter Affiliation: ConocoPhillips Company
Document Control Number: EPA-HQ-OAR-2002-0058-2867.1
Comment Excerpt Number: 15

Comment: Consider all costs and burdens in the MACT rule analyses and in the analyses required under other applicable laws and Executive Orders. The cost analysis must evaluate ALL costs associated with controls and work practices demonstrated to actually comply with the proposed emission limits and work practices being proposed. Retrofit control costs for gas-fired sources are underestimated and are not technically or economically feasible in many refinery locations due to a lack of plot space that meets required safety standards. Retrofit controls included in the EPA analysis have not all been demonstrated effective at the low emission limits proposed.

Response: See preamble for response.

Commenter Name: David M. Kiser
Commenter Affiliation: International Paper Company
Document Control Number: EPA-HQ-OAR-2002-0058-2777.1
Comment Excerpt Number: 16

Comment: The paucity of dioxin/furan data is also demonstrated within the cost estimating methodology, which does not estimate cost for dioxin/furan controls since it is assumed that dioxin/furan emissions will be below detection limits and that activated carbon used for mercury control will also control dioxin/furan. In the cost estimate for the proposed rule the following is assumed:

"it does not estimate ACI [activated carbon injection] for units exceeding the MACT floor emission limit for dioxin/furan. Instead, it is estimated that most units, when testing for dioxin/furan will be below detection levels without installing any additional control devices." [Methodology for Estimating Cost and Emissions Impacts for Industrial, Commercial, Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants – Major Source EPA-HQ-OAR-2002- 0058-0812(2)]

If this assumption that dioxin/furan will be below detection limits without installing additional controls is true, then why set a limit in the proposed rule for material which cannot be measured effectively and does not require additional control? Belief that emissions will remain below the detection limit with so much uncertainty about testing methods, meaning of test data and mechanisms of formation and control is hardly a prudent basis for assuring that compliance will be achieved on a continuous basis with prescribed emissions limits that are difficult or impossible for some credible samplers and laboratories to measure.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2702.1, Excerpt Number 10.

Commenter Name: Douglas J. Van Pelt
Commenter Affiliation: ExxonMobil
Document Control Number: EPA-HQ-OAR-2002-0058-2968.1
Comment Excerpt Number: 16

Comment: Contacted fifteen vendors for information (control efficiency, cost, etc) on application on gas fired boilers and process heaters. None of the vendors reported commercial application on gas fired units. Some vendors have application(s) on coal fired combustion sources.

The vendors indicated significant uncertainty associated with control efficiency and cost for gas fired units because of the much lower initial pollutant levels (than those from coal fired units) and the extremely low emission limits proposed, plus the lack of application experience.

To assess the emissions reductions required for the pollutants under consideration to achieve the proposed Gas 2 limits, the means of the EPA MACT floor raw data are assumed as baseline emission levels. Emission reductions for the pollutants are calculated by subtracting the baseline emissions from emissions at the proposed limits. The removal efficiencies required to meet the proposed limits and the assumed controls are summarized in the table below. (see submittal for table.)

A removal efficiency of 99.9% is required to meet the proposed limit for HCl. For units with HCl emissions above the mean of the MACT floor data, a removal efficiency of greater than 99.9% would be required. Wet scrubber is assumed to be the control. The removal requirement is higher than vendor reported typical HCl control efficiencies in waste incineration or coal combustion applications. Control technology is generally less efficient at low initial pollutant levels. Emission reductions achieved by technologies designed for much higher initial pollutant levels present in waste incineration or coal combustion applications are likely to be substantially lower when applied to the low initial pollutant levels present in flue gas from gas fired units. Therefore, 99.9% removal of HCl would not be technically achievable.

A removal efficiency of 99.4% is required to meet the proposed limit for CO. For units with CO emissions above the mean of the MACT floor raw data, a removal efficiency of greater than 99.4% would be required. Catalytic oxidation is assumed to be the control. Lowering CO through combustion controls (i.e. fuel and air controls) increases NOx, fuel consumption, and other emissions (details in Comment II). While CO is used as surrogate for organic HAPs, it is uncertain if a catalyst can achieve the same reduction efficiency for HAPs as for CO.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2960.1, Excerpt Number 275.

Commenter Name: Douglas J. Van Pelt
Commenter Affiliation: ExxonMobil
Document Control Number: EPA-HQ-OAR-2002-0058-2968.1
Comment Excerpt Number: 18

Comment: A cost impact analysis was conducted by API to evaluate cost of the proposed MACT rule for all affected sources. The study compares the API's cost estimates with the EPA's cost estimates, and finds that EPA estimates grossly underestimate the costs for compliance. EPA significantly underestimated the number of units that would be required to install controls, since they assumed units operating at or less than 400 ppm of CO, only needed to perform a tune-up rather than installing controls to achieve the 1 ppm emission level. [See Page C-5 MEMORANDUM TO: Jim Eddinger, USEPA, OAQPS/SPPD, FROM: Susan McClutchey, etal, ERG, April 15, 2010 SUBJECT: Methodology for Estimating Cost and Emissions Impacts for Industrial, Commercial, Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants – Major Source] Based on the API analysis, the total estimated capital cost for compliance for Gas 2 sources is approximately $2.4 billion (versus EPA's estimate of $1.5 billion, a 60 percent difference). This number does not even include operating costs. Costs required to operate the control devices include handling of solid waste, water use, caustic use, wastewater treatment, electricity, and maintenance.

The costs for compliance are unreasonably high while total emissions reductions are very small. As discussed in Comment II, gaseous fuels are clean burning fuels. Emissions of CO, Hg, filterable PM, and HCl from gas fired boilers and process heaters constitute less than 1% of respective total emissions from all sources nationwide. Requiring extremely low limits for gas fired boilers and process heaters will be ineffective in improving air quality.

Recommendation: EPA should evaluate the technological feasibility of applying the controls available to achieve the proposed numeric

limits to gas fired units and re-assess the cost impact of the proposed rule. EPA should not set emissions limit without regard to feasibility. EPA should avoid promulgating rules that despite requiring prohibitive capital and operating costs, will result in negligible emissions reductions, if any.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2960.1, Excerpt Number 275.

Commenter Name: David M. Kiser
Commenter Affiliation: International Paper Company
Document Control Number: EPA-HQ-OAR-2002-0058-2777.1
Comment Excerpt Number: 21

Comment: Courtland, AL - No. 2 Combination Boiler

The Courtland, AL - No. 2 Combination Boiler was identified as a floor unit for Hg and HCL in the proposed rule, however the test data for these pollutants was measured under normal operating conditions and fuel mix, and does not assure compliance under all operating conditions including the worst case fuel mix as required by the proposed rule. When the boiler was evaluated for compliance under the worst case fuel mix taking into account the variability of Hg and Cl in coal, we projected a need to install Hg and HCl controls to meet the proposed limits.

Further, we projected a need to also upgrade the existing ESP controls for PM with a bag house for removal of the additional particulate load associated with the carbon and sorbent injected for Hg/HCl control. Cost for carbon and sorbent injection and additional PM control in the form of a fabric filter is not included in EPA's cost estimates conjunction with more than 10% coal and cannot otherwise achieve the coal CO limits. In order for the CO catalyst to work along with the other required pollution control devices, we would need to reheat the flue gases to at least 450°F before the catalyst. These CO compliance costs are not currently reflected in the EPA cost estimate. This means the addition of Hg and HCl control systems at a cost of about $16 million and the CO catalyst at a cost of approximately $14 million for a total of $30 million in capital. The operating cost of these systems is $7.5 million per year not including capital recovery cost. These costs are not currently reflected in the EPA cost and economic evaluation.

Response: See response for DCN EPA-HQ-OAR-2002-0058-3213.1, Excerpt Number 7.

Commenter Name: David M. Kiser
Commenter Affiliation: International Paper Company
Document Control Number: EPA-HQ-OAR-2002-0058-2777.1
Comment Excerpt Number: 22

Comment: Ticonderoga, NY – PB1

The Ticonderoga, NY PB1 power boiler was identified as a floor unit for Hg in the proposed rule. However the test data for Hg was measured under normal operating conditions and fuel mix, and does not assure compliance under all operating conditions including the worst case fuel mix as required by the proposed rule. When the boiler was evaluated for compliance under the worst case fuel mix taking into account the variability of Hg in biomass, we determined a need to install Hg controls to meet the proposed limits along with upgraded PM controls for removal of the additional particulate load associated with the carbon. The cost for this equipment is not included in EPA's estimates for this unit. This means the addition of an Hg control system at a cost of approximately \$1.2 million in capital. The operating cost of this system is \$0.3 million per year not including capital recovery cost. This Hg control cost for a floor unit is not currently reflected in the EPA economic evaluation.

Response: See preamble for response.

Commenter Name: David M. Kiser
Commenter Affiliation: International Paper Company
Document Control Number: EPA-HQ-OAR-2002-0058-2777.1
Comment Excerpt Number: 23

Comment: Complying with the proposed Boiler MACT rule will cost International Paper an estimated \$629 million in capital cost and a total annualized cost (including capital charge) of approximately \$199 million dollars per year. This does not include the fuel replacement and disposal costs of the non-hazardous secondary materials designated as solid waste to avoid CISWI requirements. [see submittal for Attachment 1]

The basis for these cost estimates is included in Attachment 1 [The content of this attachment is confidential business information and has been submitted separately for inclusion in EPA's confidential business information files.] These costs are for IP's fleet of 42 boilers affected by Boiler MACT presuming CISWI is avoided altogether. The current limits are more stringent than needed to assure appropriate protection of health and the environment from industrial boiler HAP emissions. Using its discretionary authority under the CAA would allow EPA to craft appropriate rules that should yield more pragmatic regulatory results. International Paper also will experience annualized costs for the NHSM rule in the estimated amount of \$287 million per year and combined with Boiler MACT amounts to an estimated \$486 million per year.

Response: See response for DCN EPA-HQ-OAR-2002-0058-0856.1, Excerpt Number 2.

Commenter Name: David M. Kiser
Commenter Affiliation: International Paper Company
Document Control Number: EPA-HQ-OAR-2002-0058-2777.1
Comment Excerpt Number: 25

Comment: Not all required pollution control equipment is included in EPA's cost estimate.

There appears to be an error in the cost estimating method for determining if a CO catalyst is required for pulverized coal units. In the document describing the methodology for cost estimating it says;

"For PC-boilers, a tune-up was estimated in the cost analysis for any unit with a baseline of less than 1200 ppm @ 3% O2. The cost of a replacement LNB was estimated if CO emissions were between 1200 – 3000 ppm @ 3% O2 and catalytic oxidation was estimated if CO baseline was greater than 3000 ppm @ 3% O2.” [Methodology for Estimating Cost and Emissions Impacts for Industrial, Commercial, Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants – Major Source EPA-HQ-OAR-2002- 0058-0812(2)]

However the CO limit for pulverized coal units is 90 ppm at 3% O2. For our pulverized coal boilers we have 8 units that burn a combination of coal and biomass and cannot meet the proposed limit without a CO control device. It is assumed for purposes of estimating compliance cost that a CO catalyst with reheat to 450 degrees F will meet the proposed limits; however this assumption, that a CO catalyst will meet compliance, is unproven as discussed elsewhere in this document. The estimate for the CO catalyst for the 8 affected units is $120 million with an annual operating cost of $63 million as shown in Attachment 1. [The content of this attachment is confidential business information and has been submitted separately for inclusion in EPA’s confidential business information files.] The current EPA estimate does not include these compliance costs for pulverized coal units firing biomass in conjunction with coal. Furthermore the cost algorithm should be revised to reflect the actual compliance cost for all units given the proposed limit of 90 ppm.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2960.1, Excerpt Number 117.

Commenter Name: Michael Hutcheson
Commenter Affiliation: Ameren Services
Document Control Number: EPA-HQ-OAR-2002-0058-2803.1
Comment Excerpt Number: 29

Comment: US EPA’s estimate of costs underestimates the costs of controls by underestimating the cost of electricity to run those controls. Electricity costs are an annual cost of control and are a major component of the annualized cost of controls estimated. US EPA uses data from the US DOE Energy Information Agency to assess the annual cost of electricity associated with the cost of control. However, the US EPA erred by using data on national average reported revenue from industrial customers per net megawatt generated. The US EPA mistakenly associates utility revenue with industrial cost data which is inappropriate. The utility revenue data utilized does not include other costs borne by customers including taxes, distribution charges and environmental or other surcharges. In addition, similar higher revenue data per megawatt generated was also available for commercial accounts, however, this data was ignored despite the fact that the Boiler MACT affects commercial and institutional boilers.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2702.1, Excerpt Number 61.

Commenter Name: Michael Hutcheson
Commenter Affiliation: Ameren Services
Document Control Number: EPA-HQ-OAR-2002-0058-2803.1

Comment Excerpt Number: 30

Comment: The US EPA improperly overestimates energy and fuel savings associated with required energy audits, annual tune-ups and required combustion controls. US EPA should not include any energy savings associated with energy audits as these audits will not guarantee any energy savings. They are only assessments. Similary, US EPA's own data shows that affected units are already conducting boiler tune-ups (page 32025 of preamble which states, "The data we have suggests that units typically conduct tune-ups"). Consequently, US EPA should expect little benefit from boiler tune-ups as these are already normal practice throughout industry. As a result, Ameren believes that the fuel savings estimate of 1 % of annual fuel consumption is an overestimate and should be revised downward to reflect realistic estimates of fuel savings.

Response: EPA has retained its estimate of 1 percent fuel savings in the final rule. See memorandum "Revised Methodology for Estimating Cost and Emissions Impacts for Industrial, Commercial, Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants – Major Source" for selecting this estimate.

Commenter Name: Richard L. Killion
Commenter Affiliation: Babcock and Wilcox Power Generation Group
Document Control Number: EPA-HQ-OAR-2002-0058-2722.1
Comment Excerpt Number: 32

Comment: Lower CO will increase NOx production and require additional NOx control equipment.

The CO limits in the proposed MACT will require burners and air systems that increase NOx. The relationship between lower CO and higher NOx has been well established. This will require additional equipment to address NOx. The EPA's evaluation of economic impact does not consider the implications on other emissions like NOx that will be affected by implementing the industrial MACT.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2702.1, Excerpt Number 106.

Commenter Name: Christopher S. Colman
Commenter Affiliation: Hovensa LLC
Document Control Number: EPA-HQ-OAR-2002-0058-2863.1
Comment Excerpt Number: 33

Comment: 7. Costs at Remote/Island Facilities
a. General
Because of the distance of St. Croix from the continental United States, costs are inevitably higher for a given capital project at HOVENSA. (See submittal for outline of higher costs):

* Direct Costs
– Wage Rates
* Relocation incentives
* Per diem
* Housing costs
* Rotational leave
* Guarantees on minimum overtime
* Retention bonus – Productivity
* Quantity of Skilled Local Craft
* Limited local availability of higher level craftsman; i.e. fitters, welders, instrument technicians, electricians
* Off-location craftsmen not always from the top quartile – best working close to home
– Limited 3rd Party Services and Resources
– Lack of Competition
– Design Requirements
* Installed Spare Equipment
* Seismic/Hurricane/Tropical/Marine Design Specifications
* Capital Spare Parts Requirements
– Transportation Costs
* Ocean Freight
* Air Freight
* Vendor Representatives
* Construction Equipment
* Construction Tools
* Off-location Personnel
* Higher Turnover Rate
--Equipment and Tools Rental Durations
--Mobilization and Demobilization Travel pay to/from location
•
At HOVENSA, the result of these factors is that for a given capital project, costs for those projects are 1.3 to 2.3 times higher on average. We believe this is typical for non-continental facilities.

Response: See preamble for response.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 126

Comment: EPA Has Underestimated the Cost of Boiler MACT

In this rulemaking, EPA has followed the costing assumptions and techniques in the OAQPS Control Cost Manual (EPA 452/B-02-001). ACC continues to believe this approach underestimates the total installed cost of air pollution control equipment. The Control Cost Manual has not been updated in many years, does not reflect the current costs, and is missing information on several control technologies. Because of these limitations, ACC believes EPA has grossly understated the capital and annualized costs of this proposed rule.

Due to the anticipated major financial impact of this rule on our industry, ACC has also estimated the capital costs for installation of additional control technologies on existing boilers and process heaters. ACC did not consider potential cost reductions that might result from emissions averaging or inclusion of health based emission limits in the final rule, and we assumed that the Gas 1 limits discussed in the preamble would not be promulgated. The approach used by ACC to estimate capital costs differed from EPA's in several respects, as described below.

We developed [see submittal for Appendix A, boilers Inventory costs.] a detailed spreadsheet estimating the costs for the proposed rule, based on EPA's major source boiler inventory database table.[See Appendix A (Boiler Inventory 07-09-2010 Costs.pdf).] Since the proposed rule does not include emission limits for natural gas boilers or boilers less than 10 MMBtu/hr heat input, these units were not included in the cost analysis. Based on the information in the EPA emissions database on boiler size, fuel, existing controls, and emissions, we estimated costs of controls that would likely be necessary to comply with the proposed standards for coal, biomass, liquid, and Gas 2 boilers and process heaters.

Information from various sources was used to determine a base capital cost for a 250 MMBtu/hr boiler for each PM and HCl control technology option and then scaled using a 0.6 power function based on the size of each boiler/process heater in the inventory. For example, the base capital cost of a scrubber on a 100 MMBtu/hr boiler is calculated as the base cost of $8 million times (100/250)0.6. A fixed capital cost of $1 million was assumed for installation of a carbon adsorption system for Hg and/or dioxin control, as these systems do not vary much in cost by boiler size. A fixed capital cost of $2 million was assumed for CO controls (either projects to improve combustion or fuel feed or installation of a CO catalyst). Base cost assumptions are presented in Appendix A [see submittal for Appendix A.] It should be noted that the goal was not to create a worst-case cost estimate for each boiler. Rather, the cost estimates represent median costs for the various control scenarios based on published reports, industry and vendor information on specific project costs, EPA reports or control device fact sheets, or actual BACT or BART analyses previously submitted to permitting agencies.

To estimate capital costs for each boiler, we assumed that if there was no emissions information available for a particular boiler or process heater, the unit would likely need MACT installed, which EPA stated in the preamble to the proposed rule is a fabric filter (FF), carbon injection, wet scrubber, and combustion improvements (or CO catalyst). For PM, if a unit did not already have a FF or ESP and there was information that indicated the unit cannot meet the proposed limit or there was no emissions information, we assumed a new FF. If the unit already had a FF or ESP and there was information that indicated the unit cannot meet the proposed limit we assumed an upgrade to the existing control equipment. To estimate control costs for HCl, if there was information that indicated the unit cannot meet the proposed limit or if there was no emissions information, we assumed either a scrubber upgrade or new scrubber depending on whether the unit currently had a scrubber. For Hg and dioxin, if there was information that indicated the unit cannot meet the proposed limit or if there was no emissions information, we added carbon injection. For CO, if there was information that indicated the unit cannot meet the proposed limit and it is not a fluidized bed boiler, stoker boiler, suspension boiler, or dutch oven, then we assumed that capital would be necessary to either perform combustion and/or fuel feed improvements or other boiler/process heater improvement projects to reduce CO or install a CO catalyst.

Although EPA's estimates indicate that the total capital cost will be $9.5 billion, ACC has estimated that the total capital cost of the rule will exceed $20 billion for industry, with $3.8 billion in costs for the chemical industry (boilers listed as NAICS 325 in the EPA database). It is evident based on our analysis that major capital investments in add-on control technology will be required for continued operation of chemical industry boilers if the rule is finalized as proposed.

While the above estimate appears very high compared to the EPA estimate, we believe this estimate to be very conservative, since this methodology assumed that controls could actually be installed and could actually achieve the emission levels proposed by EPA. Realistically, many units will simply not be able to be retrofit with controls and/or will not be able to meet the emissions limits regardless of controls, so that total combustion unit replacement would be required, which would greatly expand the cost of the rule for individual facilities. Based on feedback from ACC members, replacement of boilers and process heaters will occur at many facilities because the existing units cannot be retrofitted with the required controls due to 1) lack of space for the required controls at the unit's current location, or 2) potential structural issues with the existing unit. That inability to retrofit or meet the emission limits will either result in (1) shutdown of marginal production facilities with a loss of jobs and collateral negative economic impact at all social levels or (2) addition of significant capital cost, since the cost will include not only control equipment necessary to meet new source requirements, but the cost of the replacement unit as well. We believe that EPA has failed to consider these likely impacts since it has simply not considered achievability of the emission limits it is proposing. Without this consideration, the true cost and collateral impacts of the proposed rule are not fairly represented or discussed, calling into question the legitimacy of this rulemaking.

Response: See preamble for response.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 136

Comment: EPA used a catalyst cost of $959.25 per cubic foot from Chapter 2 of the OAQPS Control Cost Manual, according to Table 1 of the ERG cost methodology memo. [EPA-HQ-OAR-2002-0058-0803]We assume this means Section 3, Chapter 2, VOC Destruction Controls, dated 2002. Page 2-45 indicates that this cost is based on a 1998 estimate of $650/cubic foot, and we assume that ERG scaled this estimate up to 2008 dollars. Based on a May 2009 cost estimate obtained from BASF by our consultant, URS Corporation, for use in a BACT cost estimate for a CO catalyst on a forest products industry boiler, BASF estimated a cost of $4000 per cubic foot for catalyst modules and supports. As EPA has other information from BASF regarding their technology in the docket for this rulemaking, [EPA-HQ-OAR-2002-0058-0781] EPA should also have confirmed its cost estimating techniques for CO catalyst installations rather than using outdated cost methodology applicable to catalytic oxidizers for VOC control, which are of different design than a CO catalyst system. EPA should update its CO catalyst costs.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2698.1, Excerpt Number 14.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 137

Comment: We do not agree with the methodology used to determine the cost of CO emissions reductions for boilers with CO emissions less than 400 ppm @3% O2. The ERG cost and emissions impacts memo states that the cost of a tune-up was estimated if the unit's baseline emissions exceeded the floor for CO but were less than or equal to 400 ppm at 3% O2. Based on conversations with boiler and burner vendors, there are certain boiler and burner designs that cannot achieve the proposed emission limits with a simple tune-up, especially in cases where a low NOx limit must simultaneously be achieved or where biomass is being burned with coal. For combination coal/biomass stoker boilers to achieve the 50 ppm CO limit, it will take more than a tune-up; it will likely take more expensive fuel feed and/or combustion improvements. For many liquid and gas boilers to achieve a 1 ppm CO limit, it will take more than a tune-up; these boilers with low NOx limits will likely face installation of a CO catalyst, which has not been proven to achieve the proposed emission levels on boilers and process heaters. The ability to retrofit CO catalyst systems on existing boilers and process heaters is a major issue that should be addressed by EPA.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2960.1, Excerpt Number 117.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 138

Comment: We do not agree with the methodology used to determine the cost of CO emissions reductions for liquid and gas-fired boilers. The ERG cost and emissions impacts memo states that if baseline CO emissions were between 400 and 1000 ppm for boilers and process heaters designed to burn liquid and gaseous fuels, the cost of a low-NOx burner was estimated to achieve the proposed MACT floor emission limits. The CO limits for these boilers in the proposed rule are 1 ppm. Based on conversations with burner vendors, a low-NOx burner is typically guaranteed to produce CO emissions of 50 to 100 ppm for gas and liquid boilers. Recently installed burners have not been shown to achieve the proposed CO emission levels. EPA's unfounded assumption that burner retrofit can result in achieving these levels is simply unfounded, and the Agency should provide justification for why they believe this is an appropriate approach or re-evaluate its assumption.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2960.1, Excerpt Number 117.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 139

Comment: EPA's cost estimates for CO controls assume that tune-ups and LBMS will achieve very high CO reductions. This assumption is false and may stem from a misunderstanding of how industrial systems are operated. Much of industry has been operating under extreme financial constraints and lowering costs has been a high priority for a long time. Many combustion units are routinely operated at optimum efficiency so that there is no further opportunity for combustion efficiency adjustment. In fact, EPA's proposed approach to tune-ups with a focus on minimizing CO emissions will, in most cases, result in use of increased excess air and thereby decreased efficiency and increased emissions overall, counter to EPA's contention of a 1% efficiency improvement with tune-ups. EPA's total estimated capital cost of $13.9 million for combustion controls and oxidation catalysts presented in Table 2 of the cost and emissions impacts memo is extremely low and a gross underestimate of the actual costs that industry boilers will incur to comply with the CO limits in the rule. The liquid and Gas 2 limits of 1 ppm in particular will impose extremely high costs for control on some units. EPA should re-evaluate its assumptions with respect to the effect of tune-ups on emission levels and fuel use.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2960.1, Excerpt Number 117.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 140

Comment: EPA has estimated that activated carbon injection will only be required on 155 existing boilers because installation of a fabric filter is expected to achieve the mercury emission limits, except in cases where a unit already has a fabric filter and does not meet the limits. We do not agree that fabric filters will be sufficient to reduce mercury emissions to the ultra-low levels proposed in this rule. There are a number of flaws in EPA's logic that fabric filters are expected to achieve mercury emission limits. First, there are many boilers in the database that are equipped with fabric filters and have measured mercury emissions higher than the proposed limits. Second, when burning fuels containing mercury with fuels containing sulfur (e.g., biomass with TDF, oil, or coal), mercuric sulfate is formed, which is a particulate that can be captured in a fabric filter, but when fuels such as biomass and natural gas with low mercury contents are burned without sulfur-containing fuels, elemental mercury is the primary emission and is not captured in a fabric filter. EPA's estimated industry-wide capital cost for activated carbon injection presented in Table 2 of the cost and emissions impacts memo is extremely low, at only $9.5 million. We do not understand how this can represent 155 boilers; it seems to us to represent the cost 10 boilers would incur to install a carbon injection system. EPA should re-evaluate its mercury control costs.

Response: See response for DCN EPA-HQ-OAR-2002-0058-3213.1, Excerpt Number 19.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 141

Comment: In its Methodology for Estimating Cost and Emissions Impacts for Industrial, Commercial, Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants – Major Source document, EPA estimated that an ESP would be installed to meet the PM emissions limit unless a unit already had a fabric filter installed. We believe that since sorbent injection will be required for acid gas, mercury, and dioxin control, that fabric filters will likely be chosen for units without existing ESPs in order to maximize the performance of the sorbents and minimize the amount of sorbent used. For example, use of an ESP will require 4 times the carbon to be injected for mercury/dioxin control than if a fabric filter is used. Using EPA's cost algorithms, installation of a fabric filter has a higher capital cost than installation of an ESP; therefore this assumption results in an underestimate of the capital cost required to meet the proposed PM limits.

Response: See response for DCN EPA-HQ-OAR-2002-0058-3213.1, Excerpt Number 20.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 142

Comment: EPA has estimated costs to install packed bed scrubbers for HCl control. Industrial boilers do not use packed bed scrubbers for acid gas control, as the limitations of these devices make them impractical for use on applications with high flow rates, high PM loading, and high inlet pollutant concentration. EPA's own fact sheet on these devices, [Available at http://www.epa.gov/ttn/catc/dir1/fpack.pdf] lists limitations of these devices, indicating that they are only used in applications up to 75,000 scfm, which limits their use to small units only. EPA has estimated HCl control costs for equipment that industry is not likely to install. Instead, facilities will install wet scrubbers, dry scrubbers, or semi-dry scrubbers to control acid gas emissions from industrial boilers. In addition, no consideration was given for facilities that may have zero discharge permits, where it is infeasible to install a wet control device. EPA should re-evaluate its cost estimates for HCl control.

Response: See response for DCN EPA-HQ-OAR-2002-0058-3213.1, Excerpt Number 21.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 143

Comment: EPA presents several cost options in the two ERG memos. Option 2E assumes that facilities will not incur costs to comply with the dioxin/furan standards because they will test for dioxin/furan and be below detection levels. This assumption is unrealistic, especially because EPA has not outlined in the rule any procedures for handling non-detects when performing compliance testing and there are boilers in the EPA emissions database with dioxin/furan emissions that are non-detect but actually measured emissions higher than the proposed limit. EPA should re-evaluate its cost estimates for dioxin/furan compliance. More detailed comments on detection limit issues and the dioxin/furan emissions data were presented earlier in this document.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2702.1, Excerpt Number 10.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 144

Comment: The costs for initial tune-ups and energy audits were annualized over 5 years. We do not believe it is appropriate to annualize these costs over a period of years, as these are services, and they must be paid in year 1 to the individual or company performing the work.

Response: See preamble for response.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1

Comment Excerpt Number: 149

Comment: Revisions to the Proposed Rule are Needed to Reduce the Cost of Boiler MACT. The capital requirements resulting from the proposed rule could be significantly reduced if EPA adopts the recommendations detailed below including the alternative total selected metals limit, work practices instead of Gas 2 and dioxin/furan emission limits, flexible emissions averaging provisions, and an alternate approach to the current pollutant-by-pollutant approach to setting the limits.

Response: See preamble for response.

Commenter Name: Daniel Moss
Commenter Affiliation: Society of Chemical Manufacturers and Affiliates
Document Control Number: EPA-HQ-OAR-2002-0058-2926.1
Comment Excerpt Number: 1

Comment: Many SOCMA member facilities, however, are major sources under Section 112. The Major Source Boiler proposed rule is of major concern to these members. As proposed, this rule would impose significantly higher costs on industry than EPA anticipates, and be extremely burdensome to an already battered manufacturing sector.

Response: *******cost issue
See anwer for
Document Control Number: EPA-HQ-OAR-2002-0058-2601
Comment Excerpt Number: 3

Commenter Name: Tom Piccorelli
Commenter Affiliation: Oberlin College
Document Control Number: EPA-HQ-OAR-2002-0058-2961.1
Comment Excerpt Number: 1

Comment: A single theme lies at the center of our comments on the proposed Industrial Boiler Maximum Achievable Control Technology (MACT) standard — the proposed standards are far more stringent than needed to assure protection of health and the environment from industrial boiler Hazardous Air Pollutants (HAP) emissions. Oberlin College fully supports measures that truly protect health and environment. But Oberlin College, like others, is challenged by the severe economic downturn and aggressive competition from other private and public colleges. None of us can afford to spend limited financial resources unwisely and we urge you to reconsider elements of the Industrial Boiler MACT standards which we believe, in their present form, are complicated and expend limited resources needed for educational and deferred maintenance programs.

Response: See response for DCN EPA-HQ-OAR-2002-0058-1876, Excerpt Number 3.

Commenter Name: Richard T. Weber
Commenter Affiliation: Flakeboard America
Document Control Number: EPA-HQ-OAR-2002-0058-2915.1
Comment Excerpt Number: 1

Comment: The proposed Industrial Boiler MACT standards are far more stringent than needed to assure protection of health and the environment from industrial boiler HAP emissions. We are committed to operating in an environmentally responsible and sustainable manner. However, as an industry we are facing a withering economic slump and fierce competition from overseas. Therefore, it is imperative for mandatory environmental controls such as the Industrial Boiler MACT standard to be tailored as closely as possible such that health and the environment are protected without requiring unnecessary expenditures of time and resources. EPA has the legal discretion and technical justification to substantially reduce the burden of the standard while still providing ample protection to health and the environment.
EPA can provide reasonable approaches in its final Boiler MACT rule that will improve air quality and target investments strategically, preventing severe job losses and tens of billions of dollars in unnecessary regulatory costs.

Response: See response for DCN EPA-HQ-OAR-2002-0058-1876, Excerpt Number 3.

Commenter Name: Paul N. Cicio
Commenter Affiliation: Industrial Energy Consumers of America
Document Control Number: EPA-HQ-OAR-2002-0058-2752.1
Comment Excerpt Number: 3

Comment: Industry experts estimate that the Boiler MACT will cause significant fuel switching from coal to natural gas and increase demand between .65 TCF to .85 TCF in a relatively short time period. That is a lot of new demand. To put this figure in perspective, according to the EIA, a .65 TCF increase in demand is equal to a 3% increase in national demand and equal to demand levels that the EIA forecasted for 2025. From 1996-2008, natural gas demand increased only 2.81%. As demand increases for natural gas, the price of natural gas and electricity will rise not just for manufacturers, but for all consumers.
The proposed boiler MACT creates emissions standards that are unnecessarily stringent using questionable methodologies that will significantly increase the cost of energy for IECA members. This increase in costs will make the industries less competitive causing some to eliminate their US manufacturing operations. IECA proposes that EPA develop more reasonable standards that are achievable in practice, consistent with Clean Air Act requirements.
IECA believes the EPA has overstepped its bounds. EPA has failed to make a compelling case that such aggressive requirements are necessary within the discretion that the agency has in

setting these standards, result in tangible improvements to health and the environment, and are justified by cost-benefit analysis.

Response: See response for DCN EPA-HQ-OAR-2002-0058-1876, Excerpt Number 3.

Commenter Name: Douglas A. McWilliams
Commenter Affiliation: ArcelorMittal USA, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2811.1
Comment Excerpt Number: 6

Comment: The economic analysis is clear. Units that recover usable energy from flared coke oven gas should be exempt. The Proposed Rule sets numeric emission limits for 5 pollutants (PM, HC1, mercury, dioxinlfurans, and CO). At this time, coke oven gas-fired units are not controlled for these compounds. Using EPA's projected cost of control (annualized capital cost + annual operating cost) for each pollutant including monitoring, recordkeeping and reporting, we calculated an annualized cost of control at $8.4 million for a single 650 MMBtu/hr combusting coke oven gas. At $5/MMBtu for natural gas, it is economically unreasonable for the boiler operator to use COG to displace the first 1,680,000 MMBtu per year of natural gas in this boiler. This immediately sends COG back to the flare for boilers relying on COG to supplement blast furnace gas combustion. These units would immediately use natural gas to replace COG to the detriment of the environment and our energy policies.company will invest $8.4 million in annualized control costs, it will need to justify a return on the capital investment far greater than $8.4 million in displaced natural gas. Capital investments typically require a return on investment of 2 years or less in the current capital-constrained environment. For the coke oven gas-fired boilers that we operate (<60% COG heat input rate mixed with BFG and natural gas), it is not possible to recover the cost of capital in two years for this project. [Footnote: The capital cost for controlling this model unit is $27,747,000 and the annual operating cost is $5,678,000. Excluding the 10% coke oven gas that could be burned with natural gas in a unit that qualifies for Gas-1 work practices, the annual benefit from displaced natural gas for a Gas-2 unit is $4,337,000, which does not cover the capital invested or controls for over six years.] In fact, the estimated return on investment is more than six years when compared with a baseline case that would not require control equipment. [Footnote: The base case assumes that a unit combusting >90% (Natural Gas + BFG) would qualify for the Gas-I subcategory. If the distinction between Gas-1 and Gas-2 remains in the final rule, EPA must clarify how BFG heat input is to be considered in the subcategory threshold analysis. Currently, a unit burning less than 90% natural gas and less than 90% BFG falls through the regulatory cracks. It is not a unit "designed to burn Gas-1" and it is not excluded as a blast furnace gas fuel-fired boiler. If the 90% natural gas threshold remains for Gas-1, BFG heat input should be counted toward that annual threshold.] The Proposed Rule will also eliminate new projects currently in the pipeline that are designed to use flared COG to displace natural gas because the capital cost to meet Gas-2 emission limits would render these projects economically infeasible.

Response: If units firing COG can demonstrate they meet the specifications outlined in the final rule for H2S and mercury they will be subject to work practice standards in lieu of emission limits. The 90 percent threshold has been removed from the final rule gas 1 subcategory definition, see the final rule for the modified definition.

Commenter Name: Deb Hastings
Commenter Affiliation: Texas Oil and Gas Association
Document Control Number: EPA-HQ-OAR-2002-0058-2857.1
Comment Excerpt Number: 12

Comment: EPA has severely underestimated the number of units affected by the control requirements and
has therefore underestimated the negative impact of this proposal on the economy and on jobs.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2960.1, Excerpt Number 117.

Commenter Name: Douglas J. Van Pelt
Commenter Affiliation: ExxonMobil
Document Control Number: EPA-HQ-OAR-2002-0058-2968.1
Comment Excerpt Number: 17

Comment: Assuming the assumed controls would allow sources to achieve the proposed limits (though not demonstrated), a typical control system that includes the controls for a natural draft process heater developed by API is provided in Figure 10 of the submittal. In many cases, these controls would require outright replacement of the boiler or process heater due to lack of space at the unit's current location or potential structural and foundation issues. The issues and associated costs could potentially result in unit shutdown, resulting in economic and job loss.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2699.1, Excerpt Number 11.

Costs: Testing and Monitoring

Commenter Name: Garrett Tinsman
Commenter Affiliation: Sauder Woodworking Co.
Document Control Number: EPA-HQ-OAR-2002-0058-1425.1
Comment Excerpt Number: 2

Comment: We are concerned about the increased cost associated with annual testing required under this proposal. This proposed rule would increase the frequency that stack testing is

required by 150%. Even without testing for additional pollutants, this requirement would more than double the current costs for emissions testing.
In addition, the proposed rule would require Sauder to test for additional pollutants. A quote from our stack testing company shows that the annual testing would cost approximately $40,000.00 when including fuel analysis. This is a 30% increase from testing now required under our Title V permit. Given the significant increase in costs related to test frequency and test composition, we request that the frequency and content of testing be re-considered.

Response: See preamble for response.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 15

Comment: Production losses will be incurred under the provisions of this rule for process shutdowns associated with the burner tune-up requirements, CPMS calibration requirements, and special, uneconomic operations associated with the performance test requirements that must be done using the worst case conditions. This production related cost must be taken into account in evaluating the proposed rule, not only from a cost perspective, but from a feasibility perspective. For example, annual emissions testing using the worst case fuel mix on all units using a 4-hour test run time will impose tremendous operational constraints on facilities that they may not even be able to meet (e.g., for limited use units or due to lack of availability of the worst case fuel). EPA should add this cost to its burden estimates.

Response: See preamble for response.
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Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 25

Comment: * EPA has estimated a cost of $44,000 to conduct testing for all 5 pollutants. While we believe this might adequately predict the cost of a stack test for some boilers, EPA has not considered scenarios where facilities must test two different operating conditions to represent worst-case mercury and chloride inputs or where they do not have enough of their worst case fuel to complete testing in a 1 or 2 day period. EPA has not considered boilers that have dual stacks in its cost estimates. In this case, the testing cost is almost doubled. In addition, some facilities may have the capability to burn more than or less than 10 percent coal with other fuels on an annual basis, so they may have to test under both scenarios to ensure they can comply with limits under different subcategories. The cost to complete stack tests for PM, dioxin/furan, and CO and fuel analysis for chlorine and Hg was estimated to be $16,000. As the dioxin/furan lab analysis is the most costly element of the stack testing required and eliminating the HCl and Hg testing only removes one sample train and associated stack tester, we do not believe this scenario would be less than half of the cost of stack testing for all 5 pollutants, and would likely be at least $30,000 in stack testing and fuel analysis cost. Even EPA's estimate for the Phase 2 ICR testing was $54,000 for most of the units tested with standard methods. Actual costs experienced by facilities required to conduct that testing were higher than that, with some facilities reporting costs of at least $60,000 for a single series of tests. Facilities will also incur additional costs if ERT reporting is required, as this will be an extra step after producing the hard copy report. EPA should re-evaluate its testing cost estimates.

Response: See preamble for response.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 26

Comment: The cost and emissions impact memo states that boilers and process heaters designed to burn liquid fuels are expected to conduct annual compliance tests for PM, dioxin/furan, and CO, but comply using fuel analysis for HCl and Hg. As the floor units for liquid fuels are based on uncontrolled light liquid units for HCl and Hg and are theoretically based on the average of emissions achieved by the top 12 percent of liquid units, we do not agree with the assumption that the remaining 88 percent of liquid fueled units will not need controls in order to comply with the HCl and Hg limits, especially since these limits were only based on data from less than 25 boilers. In fact, EPA has data in its own database (see table Data: FuelAnalysis in EPA's database emissions_database_boilers_heaters.mdb) that shows that several facilities burn fuel oil that will not meet the proposed emission limits for HCl or Hg based on fuel analysis.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2792.1, Excerpt Number 147.

Commenter Name: Stephen R. Gossett
Commenter Affiliation: Eastman Chemical Company
Document Control Number: EPA-HQ-OAR-2002-0058-3137.1
Comment Excerpt Number: 52

Comment: EPA states in the preamble (page 32033) that the proposed compliance requirements "ensure compliance with the proposed rule without imposing a significant burden for facilities that must implement them." We disagree with this statement. The proposed performance testing requirements do pose a significant burden.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2905, Excerpt Number 27.

Commenter Name: Stephen R. Gossett
Commenter Affiliation: Eastman Chemical Company
Document Control Number: EPA-HQ-OAR-2002-0058-3137.1
Comment Excerpt Number: 56

Comment: Our experience would indicate that EPA's cost estimate is low. We paid about $20,000 just for D/F tests that included just 150 minute test runs during the 2009 ICR Phase II testing. We would estimate about $60,000 to conduct the tests for PM, D/Fs, Hg, and HCl. The requirement for 4 hour runs would require two testing days instead of one, running up costs considerably for a test, not to mention the logistical difficulties of successfully running a test and working around operational disruptions.

Response: See preamble for response.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 306

Comment: Requiring the ERT will add time and cost to stack testing projects, as time will have to be spent entering the test data into the tool and then quality assuring the ERT output. We do not believe that EPA has included this extra cost in their analysis.

Response: The final rule has retained the ERT reporting mechanism. EPA recognizes that there have been some issues with the use of the ERT and we have worked closely with stakeholders to identify and correct these issues. As with all new systems, there are always transition problems as changes to those systems are implemented. Nonetheless, EPA is committed to electronic compilation and submittal of data as demonstrated by the requirement to report data electronically in the Toxic Release Inventory and greenhouse gas electronic reporting programs. We worked (and continue to work) closely with stack testing companies to set up the ERT and have the ERT process mimic most of their work when producing a final performance test report. We believe that there is a learning curve for using the ERT and it will take a few tests and reports to become proficient in its use. However, as users continue to employ the ERT, the time, effort, and subsequent costs needed to produce, review, process, and extract information from the report will decrease. The extended implementation date into 2012 for use of the ERT will also allow adequate time for users to become familiar with the process and allow us to address most of the concerns by the commenters.

Commenter Name: David A. Buff
Commenter Affiliation: Golder Associates Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2801.1
Comment Excerpt Number: 3

Comment: Only a few existing bagasse boilers have CO continuous emission monitoring system (CEMS), and none have PM CEMS

CO CEMS for 21 boilers; PM CEMS for 23 boilers

Response: See preamble for response.

Commenter Name: Chris Greissing
Commenter Affiliation: Industrial Minerals Association
Document Control Number: EPA-HQ-OAR-2002-0058-2740.2
Comment Excerpt Number: 12

Comment: EPA Incorrectly Estimates the Burden of CO Monitoring. The Proposed Rule 63.7525(a) requires large sources (heat input capacity of 100 MMBtu/hr or greater) to operate a continuous emission monitoring system ("CEMS") for CO and oxygen. EPA justifies its decision to use CO as a surrogate for organic HAP in part because "many sources currently have CO CEMS." 75 Fed. Reg. at 32018. However, while some sources may have existing continuous CO analyzers, these CO analyzers are often ancillary in nature and are not certified CEMS. A requirement for CO CEMS, therefore, will require expensive installation of many new CEMS.

A certified CO CEMS requires a considerable financial investment in both capital and operational costs including daily operation, scheduled maintenance, reporting and recordkeeping, robust spares parts inventory, and the necessary cylinder gas audits and annual RATAs. At the same time, if a source has existing CO equipment, it may be incapable of accurately measuring CO concentrations of 30-90 ppm for purposes of this rule – these units have been commonly available in 0-2500 ppm to 0-10000 ppm full span, which are not appropriate for measuring CO at the levels of the proposed CO standards. These analyzers would either require significant modification or need to be replaced with new CO instruments having the appropriate span range.

Response: See preamble for response.

Commenter Name: Randall D. Quintrell
Commenter Affiliation: Georgia Paper and Forest Products Association, GPFPA
Document Control Number: EPA-HQ-OAR-2002-0058-2905
Comment Excerpt Number: 19

Comment: GP&FPA has facilities with multiple boiler units. At least one facility has 6 boilers that will be subject to the Rule. It is easy to see that trying to schedule such long duration tests and so many tests for potentially 2 or more fuel mixes will quickly become unmanageable especially on a 10 month repeat frequency. The testing would simply never end. This is exacerbated by the need to test at high rates that may not be sustainable over the prescribed long test periods. Also, we have some facilities with a single large boiler. The unit load is entirely dependent on mill steam demand at the time and it cannot be managed to achieve a "maximum" normal over an extended test period without venting steam and wasting valuable fuel. In addition to the logistical issues associated with operating this way, the costs for such operation have not been considered in EPA's testing cost estimates.

There are additional logistical problems related to physical constraints on testing facilities. To run tests for different parameters at the same time, which must be done as a practical matter due to the extended test runs and required load conditions, multiple sampling trains are required. Most sampling platforms were designed for single train testing and the lack of space and port availability can make the testing significantly more difficult. Alternately it requires consecutive tests instead of concurrent testing which multiplies the cost accordingly. This lack of work space is especially critical for the sophisticated tests being conducted under the proposed Boiler MACT requirements, with emissions at or near quantitation limits with very low tolerance for variability. It also slows the testing down. Some sites might be able to increase the platform size but for many stacks, larger platforms may not be feasible. The platforms are often suspended from the stack which cannot support more weight. One mill which has conducted similar tests stated that it was extremely difficult to get more than one run per day even during the long daytime hours of summer and it would be impossible to do so in winter. With setup time, changing ports and testing time, a 4-hour test run consumed at least 6 hours of actual time. The mill ran three scenarios on one unit to cover fuel mixes, so there were 9 four-hour runs required. This mill has a load following boiler with load swings and mill operations had to be considered in loading the boilers during testing. The testing took 2 weeks for this one source. Multiply this by 2 to 6 boilers per facility, as many of us have, and the testing burden quickly becomes extreme.

Response: See response for DCN EPA-HQ-OAR-2002-0058-3213.1, Excerpt Number 15.

Commenter Name: Randall D. Quintrell
Commenter Affiliation: Georgia Paper and Forest Products Association, GPFPA
Document Control Number: EPA-HQ-OAR-2002-0058-2905
Comment Excerpt Number: 22

Comment: GP&FPA mills which have recently conducted similar testing (either as part of the 2009 ICR testing or in preliminary testing for internal reasons) have reported a range of costs for the performance testing contractor. The costs have ranged from $65,000 to $90,000 for a single set of tests. No data have been developed for the additional costs of the testing in terms of staff and administrative time, fuel costs and other expenses. Testing contractor costs are expected to significantly increase as demand increases with thousands of boilers required to test in a short time - particularly if the proposed 10 month schedule for retesting is not deleted.

When EPA submitted its ICR proposal to OMB in 2009 for testing of the same basic parameters now proposed as an annual requirement for each non-Gas 1 unit, they estimated the cost for testing 310 units at 16.7 million dollars, or $55,000 per test. EPA assumed 100 man-hours for administrative time per test, to manage and supervise the testing and to review the reports, adding another $6500. That is $65,500 per test per source by EPA's own estimate, which is at the low end of the range of costs our member facilities have actually incurred for Phase 2 testing or preliminary testing. These costs did not include additional fuel costs and other costs to the Mill operation in addition to stack testing contractor costs. Some of our member facilities may have as many as 5 or 6 affected units and many have multiple scenarios to test even with only one unit. For those facilities with multiple boilers and multiple scenarios, the testing costs alone could easily reach $500,000 per required testing episode. These costs do not even include testing costs for the proposed compliance monitoring calibrations and rata testing which are also excessive as proposed. The level of cost for testing as proposed is excessive and unacceptable as a periodic testing requirement and it is an "absurd result" for repetitive testing for all units, some with multiple scenarios, every 10 months!

Response: See preamble for response.

Commenter Name: Randall D. Quintrell
Commenter Affiliation: Georgia Paper and Forest Products Association, GPFPA
Document Control Number: EPA-HQ-OAR-2002-0058-2905
Comment Excerpt Number: 27

Comment: Although the initial Boiler MACT regulation2 required annual testing it adopted the standard 3-hour Method 5 which is a test routinely used by many units for Title V testing purposes. Also, the initial Boiler MACT had more reasonable emission standards, it included the 3-year relief mechanism, and it contained options for alternative fuel sampling and TSM alternative standards. These provisions resulted in a significant but not completely unreasonable testing burden on affected units. In contrast, the testing requirements in the current proposed Boiler MACT are unnecessarily burdensome, punitive, excessively costly, and we believe arbitrary and capricious.

Response: See the preamble for how EPA reduced the testing burden in the final rule.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 83

Comment: From review of the RIA, it does not appear that the costs and burdens associated with the CO monitoring requirements in the proposed tune-up criteria were fully reflected. If these requirements are maintained and our other recommendations relative to the CO determinations are not implemented, the cost and benefit analyses will need to be corrected to include all of the costs of conducting before- and after-adjustment performance tests for determining stack moisture and oxygen. If it is concluded that use of portable analyzers is not permitted, CO measurement will need to be included as well.

Recommendations: Incorporate all required costs and burdens associated with 63.7540(a)(10)(iv) and (v) into the rule cost and benefit analyses.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2740.2, Excerpt Number 12.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 94

Comment: Attempting to meet the proposed CO limits for Gas 2- and liquid-fired boilers and process heaters will lead to increased NOx emissions and potentially increased PM2.5 and other pollutant emissions depending on the control strategies employed. This could result in making those boilers or process heaters subject to Part 60 subpart D, Db or Dc standards and/or to part 60 subpart Ja and require New Source Review and Prevention of Significant Deterioration analyses and offsets. None of these activities appear to have been addressed in this rulemaking‘s cost or burden analyses or considered in establishing the time needed for compliance. We recommend these impacts be considered as the rule is finalized.

Recommendation: The Agency should make clear in finalizing this regulation that the Part 60 General Provision’s pollution exemption applies to emission increases of criteria pollutants due to modifications associated with complying with this rule, provide a mechanism for extending compliance time where NSR or PSD permitting is needed, and incorporate the cost of that permitting and offsets in the economic and other analyses.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2960.1, Excerpt Number 286.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-2702.1
Comment Excerpt Number: 135

Comment: Our experience would indicate that EPA's cost estimate is low. CIBO members have paid about $20,000 just for D/F tests that included just 150 minute test runs during the 2009 ICR Phase II testing. CIBO would estimate about $60,000 to conduct the tests for PM, D/Fs, Hg, HCl. The requirement for 4 hour runs would required two testing days instead of one, running up costs considerably for a test, not to mention the logistical difficulties of successfully running a test and working around operational disruptions.

Response: See response for DCN EPA-HQ-OAR-2002-0058-3137.1, Excerpt Number 56.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 160

Comment: As EPA concluded in evaluating where work practice requirements are justified by 112(h), it is quite costly to install platforms and structural facilities to support monitoring stacks. It does not appear from our review of the docket that the Agency cost estimates for CEMS included these costs. In some cases, total stack replacement will be required to allow safe installation, operation and maintenance of the CEMS specified under this rule.

Recommendation: Revise the CEM cost estimates to reflect the costs of stack platforms and access and, in a percentage of cases, stack replacement.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2960.1, Excerpt Number 298.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 161

Comment: The RIA cost and burden analyses included all of the costs burdens, recordkeeping and reporting associated with the QA/QC of parameter and emissions monitors. An effort appears to have been made to include the initial effort associated with developing a monitoring QA/QC plan, but there does not appear to have been any upkeep estimate for that plan or any estimate for the on-going costs and burdens associated with the requirements specified in proposed 63.7525 for all compliance monitors. This is particularly important for CEMS, because the burdens associated with RATA testing are very extensive.

Recommendation: Adjust cost and burden estimates to account for the QA/QC requirements specified in the rule and in the General Provisions and fully account for the RATA testing of required CEMS.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2960.1, Excerpt Number 300.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 172

Comment: Where chloride and mercury controls are in place, annual performance tests are required for chloride and mercury. Separate performance tests for each of these species will be needed in order to test at maximum chloride and mercury as required by the rule, since the maximums usually occur in different fuels. Additionally, the proposal requires that whenever a performance test is performed CO, PM and dioxin/furans be determined. Thus, where chloride and mercury controls are in place (94% of the units with chloride and mercury emission limits), all performance tests should have been estimated on the basis of performing two tests and of testing for all species.

Recommendation: Adjust rule cost estimates and analyses to reflect separate performance tests for any performance test of a unit where chloride and mercury controls are in use.

Response: See preamble for response.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 173

Comment: Proposed 63.7515(b) through (d) provide for exceptions to the annual testing requirement if emissions do not exceed 75% of the emission limit after three stack tests. However, these provisions do not apply to dioxin/furan monitoring, so they provide no real relief, since a large part of the cost for a stack test is the set-up (including operational setup) and the flow, oxygen and moisture testing. Sources with emissions limits will still have to stack test annually and will have to disrupt operations to bring the boiler or process heater to stack test conditions.

Recommendation: Assure that cost estimates and regulatory analyses reflect the requirement to annually test for dioxin/furans at all units and that the costs and burdens associated with that testing are valid.

Response: See response for DCN EPA-HQ-OAR-2002-0058-3137.1, Excerpt Number 56.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 185

Comment: The extra cost and effort for submitting this information electronically is not included in the cost and burden estimates.

Recommendation: Adjust all cost and burden estimates for the additional cost of submitting performance test results electronically.

Response: See response for DCN EPA-HQ-OAR-2002-0058-3213.1, Excerpt Number 306.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 194

Comment: EPA cost estimates in the RIA and other supporting documents assumed fuel testing for liquids, but not for solids or gases. Fuel sampling costs and burdens should be assumed for at least the small proportion of sources firing gases or solids that are subject to emission limits and operating without controls.

Recommendation: Add fuel sampling costs and burdens to the cost and burden estimates for gas and solid fueled units.

Response: See preamble for response.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)

Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 221

Comment: The cost and burden estimates fail to address the large effort that will be associated with permitting all of these changes and performing the New Source Review analyses required because of the increases in criteria pollutants that will result from this proposal. Similarly, while the rule supporting estimates incorporate a small amount of time for an initial reading of the regulation, they include no costs or burdens for ongoing training or for the massive effort associated with incorporating these new requirements into site compliance programs, both initially and as new boilers and process heaters are added.

Recommendation: Adjust the cost and burden estimates for the permitting and compliance system modification costs necessary for achieving compliance with this rule.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2960.1, Excerpt Number 286.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 222

Comment: The rule cost and burden analyses fail to account for the large effort associated with managing unit outages and special operations to conduct the required tune-ups and performance tests. In some cases, boilers and process units will have to be shutdown to allow burner inspections or to make repairs resulting from the inspections. In all cases, the annual tune-up and performance testing will require operating the boiler or process heater at specific high rate conditions and often with unusual feeds to meet the requirement for maximum mercury and chloride in the feed during performance tests. Significant engineering effort will be required to manage these special operations, particularly for process heaters which typically are not spared and thus the entire process will have to be run non-optimally.

Recommendation: Adjust cost and burden estimates for the engineering and operational efforts needed to accommodate the proposed tune-up and performance test requirements.

Response: See response for DCN EPA-HQ-OAR-2002-0058-3213.1, Excerpt Number 15.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 276

Comment: [See submittal for TABLE 1-2. COMPARISON OF API AND EPA COST IMPACT ESTIMATES FOR GAS 1 ($/YR)]

The total annual cost impact of compliance for Gas 1 with BPH NESHAP emissions limits is approximately $13.6 billion, approximately 80 percent higher than EPA's cost estimate of $7.6 billion. The difference in costs are primarily due to underestimated costs associated with pollution control upgrades (discussed above) and with testing and monitoring requirements.

The total annual estimated cost impact of compliance is approximately $0.87 billion, approximately 88 percent higher than EPA's cost estimate of $0.46 billion.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2960.1, Excerpt Number 301.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 277

Comment: [See submittal for TABLE 1-2. COMPARISON OF API AND EPA COST IMPACT ESTIMATES FOR GAS 1 ($/YR)]

EPA significantly underestimated the total cost of stack testing and monitoring for Gas 1 by approximately $700 million annually. Although EPA slightly underestimated stack testing costs on an individual per BHP unit basis, the reason for such a dramatic cost differential for the entire Gas 1 subcategory is unclear. Based on information received from an API member company, EPA's estimates for continuous emissions monitoring (both initial setup and annual costs) were significantly underestimated.

EPA significantly underestimated the total cost of stack testing and monitoring by approximately $8 million annually for the same reasons cited for the Gas 1 subcategory.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2960.1, Excerpt Number 301.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 286

Comment: MAJOR AND MINOR NEW SOURCE REVIEW (NSR) PERMITTING

In addition to the significant costs associated with companies developing compliance strategies for the BHP (also not addressed in this report), addition of new pollution control technologies and "optimization" of carbon monoxide (CO) controls can notably increase emissions of certain other criteria pollutants, which may necessitate costly and potentially problematic permitting actions. Increased emissions can result from the following:
* Reducing CO emissions to low concentrations often increases nitrogen oxides (NOx) emissions;
* Operation of catalytic oxidation controls for CO control will result in additional fuel combustion, which increases emissions of all combustion related compounds including carbon dioxide (CO_2);
* Operation of catalytic oxidation controls for CO control will result in additional particulate matter (PM) and sulfuric acid mist (SAM) emissions as sulfur dioxide (SO2) emissions are oxidized to sulfur trioxide (SO3), which converts to SAM (which is also particulate matter);
* Certain Gas 2 streams at refineries will have to be treated to remove hydrogen sulfide (H2S) emissions, resulting in higher SO2 emissions (it is our understanding that API is providing a more detailed discussion of this ramification).

The quantities of pollutants and the permitting ramifications on individual facilities are difficult to quantify because they will vary considerably based on site-specific situations. At a minimum, minor NSR permitting is required for the installation of pollution control technologies, and frequently these permitting exercises are not trivial because they can require extensive state-driven air dispersion modeling evaluations. There are a number of conceivable scenarios in which major NSR permitting could also be triggered at a site, resulting in costly and lengthy permitting efforts which may include ambient air quality impact analyses as well as application of best available control technology (BACT) or even lowest achievable emission rate (LAER). Trinity is already seeing significant complications in permitting actions due to increasingly more stringent air quality standards recently promulgated (and soon to be promulgated) by EPA. Regardless of whether minor or major NSR is triggered, there will undoubtedly be thousands of significant permitting activities across the U.S. that would be triggered due to compliance with the BPH NESAHP requirements. Such projects will involve not only significant internal and external resources for permitting, but could also require modification of plant layouts or process operations in order to comply with air quality standards.

Response: See the discussion in the preamble for changes made to CO limits and compliance requirements. EPA made several changes to incorporage measurement error and consider CO variability over various boiler loads and determined that these changes can mitigate the concerns with increased NOX emissions. EPA has also provided an estimated in the impacts section of the preamble for increased CO_2 emissions from the energy consumption used by control devices such as oxidation catalysts. EPA has also modified the definition of gas 1 to be more inclusive of gaseous fuels that can demonstrate they meet the specification for H2S and Hg. See response to comment EPA-HQ-OAR-2002-0058-0851.1, excerpt 7 for the costs of the NSR program which are not estimated as part of this rulemaking.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 292

Comment: EPA's estimated cost for the full testing program for PM, HCl, Hg, CO, and dioxin/furan are generally reasonable for single-fueled sources. However, the $7,000 reduction for the elimination of CO from the stack testing program for 100 MMBtu/hr units is overestimated. The addition of a CO to a test program that already includes the cost of mobilization would only require an additional analyzer to the setup and possibly an additional test technician. Given the low cost associated with adding CO to a test program, a $3,000 reduction from the full test scenario would be more appropriate.

Response: See preamble for response.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 293

Comment: EPA's reference to refinery gas as only requiring compliance and associated testing for mercury is unclear and is likely a reference to one of the options not included in the scope of our analysis. Obviously, since refinery gas-fired units belong to the Gas 1 subcategory, compliance with the proposed alternative emission limits would necessitate compliance testing according to Test Scenarios 1 and 2, as shown above. [See submittal for Table 3-1 EPA Testing Cost Assumptions.]

Response: See response for DCN EPA-HQ-OAR-2002-0058-2960.1, Excerpt Number 296.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 295

Comment: EPA's assumption that all BPHs equal to or greater than 10 MMBtu/hr are equipped with test ports and scaffolding is inappropriate.

Response: See preamble for response.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 296

Comment: The revised cost estimates associated with stack testing of gas-fired sources are presented in Tables 3- 1 and 3-2, respectively. [See submittals for tables.] It was assumed each unit would be required to demonstrate compliance through stack testing on annual basis for all pollutants with the exception that units equal to or greater than 100 MMBtu/hr would not test for CO because these units would be equipped with a CO CEMS.

API estimates include costs for scaffolding and test ports for all units less than 10 MMBtu/hr. The percentage of units 10 MMBtu/hr or greater needing test ports and test platforms is unknown; however, it a conservative estimate of 25% of BPHs between 10 and 100 MMBtu/hr was included in the total annual cost for these units.
[See submittal for TABLE 3-2. COSTS FOR ANNUAL TESTING OF GAS 1 SOURCES ($)]
Cost for stack testing based on EPA's estimate for PM, HCl, Hg, CO, and dioxin/furan with the exception of
sources greater than 100 MMBtu/hr where a $3,000 reduction was assumed for the elimination of CO from the test program.
Cost for test ports estimated to be 11,000 per source and an additional 14,000 per source for temporary scaffolding.
Cost for ports and scaffolding annualized based on the following:
Interest Rate: 7%
Years: 5
Assumed that 25% of BPHs in the 10 - 100 MMBtu/hr size category do not have existing scaffolding or test ports.
Assumed $2,000 for electronic data entry.

[See submittal for TABLE 3-3. COSTS FOR ANNUAL TESTING OF GAS 2 SOURCES ($)]

Response: See preamble for response.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 297

Comment: CEMS PLANNING COSTS

The costs associated with the purchase, installation, and operation of CEMS is a significant capital expenditure for any facility. Given this significant expenditure, and the critical nature of CEMS design for obtaining reliable and representative data, the planning phase of such projects requires a significant amount of engineering and design work. In comparison to actual costs incurred by its members on CEMS installation projects, API has found EPA's cost estimates for planning activities to be significantly underestimated. For example, API has estimated the planning phase for the installation of a new CEMS to be as much as 40 times higher than EPA estimates.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2960.1, Excerpt Number 300.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 298

Comment: CEMS SUPPORT FACILITY COSTS

As EPA concluded in evaluating where work practice requirements are justified by 112(h), it is quite costly to install platforms and structural facilities to support monitoring equipment on stacks. It does not appear from our review of the docket that EPA cost estimates for CEMS included these costs. In some cases, API expects that total stack replacement may be required to allow safe installation, operation and maintenance of the CEMS specified under this rule. Unlike the temporary nature of stack access required for annual testing events (which can be accommodated with rented scaffolding equipment), stack ports used for continuous monitoring equipment must be accessible at all times to ensure continuous and reliable operation and to facilitate preventative maintenance and routine calibration activities. EPA's cost estimates associated with certain aspects of support facilities (e.g., installation of sampling ports, utilities, platforms and ladders, and a climate-controlled instrument/analyzer shelter) appear to be significantly underestimated. For example, API has determined the cost for the support facilities related to installation of a CO CEMS at nearly 15 times higher than EPA estimates. API's estimate is based on actual project costs to install such systems, and includes the costs for stack modifications (addition of ports and access platforms) as well as the installation of a climate-controlled shelter for housing the CEMS.

Response: See preamble for response.

Commenter Name: Matthew Todd and David Friedman

Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 299

Comment: CEMS INSTALLATION AND STARTUP COSTS

The cost associated with the initial installation of a CEMS includes not only the design and installation of the system, but also initial startup and troubleshooting activities as well as operator training. For a CO CEMS, API estimates that initial costs for installation would be more than ten times higher than EPA has estimated.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2960.1, Excerpt Number 300.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 300

Comment: ANNUAL COSTS

Annual costs associated with operation, maintenance, repairs, and QA/QC of CEMS include activities such as the daily activities associated with calibrations and monitor operation as well as annual Relative Accuracy Testing Audits (RATAs) testing, quarterly cylinder gas audits (CGAs), record keeping and reporting, the annual review of QA/QC Monitoring Plans and Operation and Maintenance Plans.

For overall annual costs of operating and maintaining a CEMS, API estimates costs that are approximately three times higher than EPA's estimates. API's cost estimates account for the cost of skilled instrument technician labor for daily calibration and routine maintenance and operation of the CEMS, as well as the cost of quarterly CGAs and annual RATAs, plus on-going review and updates to CEMS QA/QC monitoring plans and procedures. These costs also take into account the significant labor investment that is required to ensure that the CEMS operates with minimal downtime, undergoes periodic preventative maintenance, is supplied with adequate spare parts, and receives software updates and other upgrades as needed.

Response: See preamble for response.

Commenter Name: Matthew Todd and David Friedman

Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 301

Comment: API's revised cost estimates associated with monitoring requirements of the proposed rule are outlined in Table 4-2, Table 4-3, and 4-4 [See submittal for tables.]. These costs assume the same number of affected units that EPA used in their cost estimates. [Footnote: It should be noted that the number of affected units used in EPA's monitoring cost estimates were not clearly supported.] As discussed previously for other aspects of EPA's cost analysis for this rule, the affected units are based on the Gas 1 and Gas 2 source categories assumed to be conservatively low based on the additional sources believed to be subject to the rule but not included in EPA's calculations. It should also be noted that EPA's costs for parameter monitoring systems (BLDS, scrubber parameters, and ACI) on a per unit basis appear to be generally reasonable. However, it should be reiterated that API believes EPA has significantly underestimated the number of sources that would need to install pollution control devices to meet numerical limits in the proposed rule, which would also mean that costs associated with parametric monitoring of those control devices is also significantly underestimated. The revised cost estimates provided in this report assume the parametric monitoring system costs would be part of the capital costs of the control equipment and therefore are not addressed in this section of the report.
The revised cost estimates for CEMS included in the tables below are based on typical project costs obtained from actual projects by API members for both the initial costs and annual operating costs. API has estimated per unit CEMS monitoring costs as follows:

[See submittal for TABLE 4-2. API MONITORING COST ASSUMPTIONS PER UNIT]

When API's per unit costs shown above are then applied to the affected source counts used by EPA in their monitoring cost analysis, the total costs of compliance with the monitoring requirements of the rule are significantly higher than what EPA has estimated. The following tables show the comparison of these revised costs to EPA's estimated costs for total initial costs (TIC) and total annual cost (TAC) with capital recovery for both the Gas 1 source category as well as the Gas 2 source category.

[See submittal for TABLE 4-3. COMPARISON OF MONITORING COSTS FOR GAS 1 SOURCES ($)]

[See submittal for TABLE 4-4. COMPARISON OF MONITORING COSTS FOR GAS 2 SOURCES ($)]

Response: See preamble for response.

Commenter Name: Patrick Strauch

Commenter Affiliation: Maine Forest Products Council
Document Control Number: EPA-HQ-OAR-2002-0058-3120.1
Comment Excerpt Number: 4

Comment: From a smaller forest products manufacturer (such as a saw mill) perspective, we believe that many of our member's facilities will be forced to employ new energy audit and stack testing procedures that could cost up to tens of thousands of dollars each year. For several of our members, that is a significant cost to weigh when considering new investments into more efficient and environmentally friendly boilers.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2905, Excerpt Number 27.

Commenter Name: Jon T. Howard
Commenter Affiliation: Weston Solutions, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2737.1
Comment Excerpt Number: 11

Comment: We believe that - depending on the scope of work - use of EPA's ERT and SRTs add 8 to 24 hours per source for a mid-professional level person with previous ERT experience.

Response: See response for DCN EPA-HQ-OAR-2002-0058-3213.1, Excerpt Number 306.

Commenter Name: Douglas A. McWilliams
Commenter Affiliation: American Municipal Power
Document Control Number: EPA-HQ-OAR-2002-0058-2808.1
Comment Excerpt Number: 29

Comment: EPA acknowledges that PM CEMs will cost an average of $88,000 per unit, annualized to $33,000 per unit. For a municipal utility like the City of Orrville that operates four boilers this size, these costs can quickly exceed a quarter of a million dollars. This is a significant cost burden, particularly for small entities that may already be required to spend millions on control equipment to comply with proposed emission limits. Yet EPA has provided no justification for imposing this additional cost.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2875.1, Excerpt Number 7.

Commenter Name: David Foerter
Commenter Affiliation: Institute of Clean Air Companies
Document Control Number: EPA-HQ-OAR-2002-0058-2937.1
Comment Excerpt Number: 37

Comment: FID analyzers utilize flame ionization technology to continuously measure total hydrocarbons in a variety of gaseous sample matrices. FID analyzers are basically carbon counters and can measure accurately from single-digit ppm to low percent levels of hydrocarbon concentrations. FID technology is accepted as a method of choice for total hydrocarbon measurements and meets EPA method 25A for compliance monitoring and 1065 for automotive testing requirements. The cost for an FID analyzer for THC is about $13,000. For both methane and non-methane THC, its about $17,000.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2740.2, Excerpt Number 12.

Commenter Name: Ann W. McIver
Commenter Affiliation: Citizens Energy Group
Document Control Number: EPA-HQ-OAR-2002-0058-2875.1
Comment Excerpt Number: 7

Comment: In the preamble discussion, EPA suggests that the initial capital cost for PM CEMs monitoring is estimated to be $88,000 per unit. In order to understand EPA's estimated costs in the context of our facility, Citizens contacted vendors with experience in the installation and operation of continuous emissions monitoring equipment, including PM CEMs. These vendors provided budget estimates for the installation at a site equipped with data acquisition system equipment (needed to manage the data), as well as a location with sufficient stack access to the equipment.

Depending on whether the facility has a dry or wet stack, the procurement and installation of the PM CEMs ranges from $55,000 to over $100,000, which may be represented by EPA's estimate of $88,000 per unit. However, in addition to the equipment, there are additional costs that must be factored in, including data acquisition and management, and initial certification costs.

The estimated cost for the installation of the data-management side, including configuration of a data acquisition system to manage the data produced by the CEMs, exceeds $10,000, and estimates for the initial certification testing of the CEMs range from $30,000 to $50,000. These costs may add an additional $40,000 to $60,000 to the capital costs. Additionally, for facilities lacking existing infrastructure for CEMS, the addition of a stack platform, access, GEMS shelter, and utilities can easily exceed $100,000 per stack.

While Citizens has not reviewed the background data used by EPA, we believe that the cost estimates that form the basis of the proposed rule may be lower than facilities are likely to encounter.

Response: See preamble for response.

Commenter Name: Robert Thornton
Commenter Affiliation: International District Energy Association
Document Control Number: EPA-HQ-OAR-2002-0058-2918.1
Comment Excerpt Number: 9

Comment: It is not clear that the EPA has adequately accounted for the total costs of controls, including not only capital costs but also ongoing operation and maintenance costs of, for example, PM CEMS and CO CEMS. IDEA encourages EPA to consider the use of parametric monitoring, including opacity and bag-leak detection equipment, in lieu of the PM CEMs as a compliance monitoring tool.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2875.1, Excerpt Number 7.

Commenter Name: Barry Christensen
Commenter Affiliation: Occidental Chemical Corp
Document Control Number: EPA-HQ-OAR-2002-0058-2848.1
Comment Excerpt Number: 9

Comment: Our research indicated that any attempt to sample a gaseous fuel for metals and chlorides requires a relatively more involved sampling train in order to ensure that adequate sample volume is obtained in order to implement the required limits of detection for the chlorine and mercury analyses. Attachment B[see submittal for sampling methods] is the hydrogen fuel sampling methods and cost suggested by our stack sampling contractor to gather updated characterization data for this fuel stream.

Response: See preamble for response.

Commenter Name: Gary W. Kruger
Commenter Affiliation: Morton Salt
Document Control Number: EPA-HQ-OAR-2002-0058-2883.1
Comment Excerpt Number: 15

Comment: Our experience from conducting ICR Phase II testing indicates that EPA's cost estimate is too low. It is estimated that about $60,000 is the cost to conduct the tests for PM, D/Fs, Hg, HCl. Given that the proposed rule requires annual testing and 4-hour runs, it will create a significant burden due to the expense of testing and operational disruptions associated with testing periods.
A performance testing frequency of once per Title V permit term, or every 5 years which is consistent with current permit obligations, would be sufficient to demonstrate compliance with the emission standards.

Response: See response for DCN EPA-HQ-OAR-2002-0058-3137.1, Excerpt Number 56.

Commenter Name: Richard Krock
Commenter Affiliation: The Vinyl Institute
Document Control Number: EPA-HQ-OAR-2002-0058-2944.1
Comment Excerpt Number: 15

Comment: To capital expenditures to meet MACT where necessary, EPA has not fully considered the cost of compliance with annual stack testing, continuous monitoring, maintenance and calibration of CEMS, personnel training to both conduct and monitor CEMS, nor submission of validated detailed test reports.

Response: See preamble for response.

Commenter Name: Brad James
Commenter Affiliation: Trinity Consultants
Document Control Number: EPA-HQ-OAR-2002-0058-2853.1
Comment Excerpt Number: 23

Comment: CEMS will be excessively costly to implement. For facilities with multiple sources, numerous new monitoring and compliance systems would be required, which will place a significant economic burden on the facilities' operation. EPA is required to take cost into account in its procedural regulations. 42 U.S.C. § 7412(d)(2)). While EPA provides an estimate for the cost of implementing a PM CEMS system, it does not explain how it obtained that number. Nor did EPA provide any analysis regarding the economic impact of the cost of installing and running CEMS systems on multiple sources. EPA merely states the proposal would be reasonable for sources with a high heat input capacity. However, heat input capacity has no connection with a company's economic stability or its ability to absorb significant additional operating costs.

Beyond its faulty cost analysis for PM CEMS, EPA provides no costs for CO CEMS, opacity monitoring, pH, pressure drop, liquid flow rate, sorbent injection rate, bag leak detection, secondary current and voltage, total power output, or any of its other mandatory compliance and monitoring measures. EPA is required to consider the costs of these systems but has failed to comply with that regulatory mandate.

Response: See preamble for response.

Commenter Name: Steven G. Hanson
Commenter Affiliation: Graphic Packaging International
Document Control Number: EPA-HQ-OAR-2002-0058-2723.1
Comment Excerpt Number: 24

Comment: GPI — Macon Mill has obtained a preliminary estimate of $65,000 for performance testing of the required pollutants for the existing biomass boiler at the Macon Mill. This represents cost for just one boiler and one fuel operating scenario (which may not be sufficient for multi-fuel boilers). Beyond the actual stack test costs from the testing firm, there are additional costs that the Macon Mill will have to absorb associated with the proposed requirements:

GPI — Macon Mill estimates potentially tripling annual stack testing costs.

Significant increase in time necessary for testing, potentially moving from one week of stack testing for existing requirements to at least two and potentially three weeks, depending on the number of fuel scenarios required for multi-fuel units. During this testing time, mill production operations can also be impacted.

During testing for the existing biomass boiler, a significant amount of coal may be required if required to combust 100% coal. This represents a substantial cost for fuel relative to normal operations simply for the purposes of testing. This also translates into additional costs for usage of caustic on the existing biomass boiler, which is only employed when combusting coal.

At least one additional operator is required during testing to oversee mill and boiler operations. Given the anticipated timing for testing, we expect overtime costs will increase by two to three times.

Response: See response for DCN EPA-HQ-OAR-2002-0058-3213.1, Excerpt Number 15.

Commenter Name: David O'Keefe
Commenter Affiliation: USEC, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-3122
Comment Excerpt Number: 27

Comment: Costs associated with an installation of a CO CEMS should be included for GHG gas monitoring plans and implementation. The additional CO monitor may require a higher tier calculation for affected facilities. This will mean added costs for plan development and implementation.

Response: See preamble for response.

Commenter Name: David M. Kiser
Commenter Affiliation: International Paper Company
Document Control Number: EPA-HQ-OAR-2002-0058-2777.1
Comment Excerpt Number: 36

Comment: EPA has significantly underestimated the cost of conducting annual performance tests when evaluating the impact of the proposed rule. [Regulatory Impact Analysis: National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters, April 2010, page C-6]

Based on recent stack test programs conducted at several IP facilities, we believe that EPA's estimate of $44,000 annual Boiler MACT stack tests should be doubled. In response to EPA's 2009 CAA Section 114 request, we performed hazardous air pollutant emissions stack test programs on boilers at 7 different pulp and paper mill locations. As would be reasonably expected, the complexity and cost of seven test programs varied based on factors such as accessibility of stack and fuel sampling locations, the distance contract test crews had to travel to the site, and the site's ability to base load the steam generation rate of the tested boiler to maintain steady operations over the span of the test periods. From this test program, the average cost associated with sampling, analyzing and reporting Boiler MACT emissions (Dioxins/Furans, Mercury, Hydrogen Chloride, Particulate Matter, Carbon Monoxide) and fuel characteristics was $85,000 per boiler for a single operating scenario (operating rate and fuel mixture). Because many of the boilers used in the Pulp and Paper Industry are designed to burn multiple fuels, many boilers will require testing under more than one operating scenario.

Response: See response for DCN EPA-HQ-OAR-2002-0058-3137.1, Excerpt Number 56.

Commenter Name: Douglas J. Van Pelt
Commenter Affiliation: ExxonMobil
Document Control Number: EPA-HQ-OAR-2002-0058-2968.1
Comment Excerpt Number: 76

Comment: EPA's proposed rule underestimates the cost of installing CO CEMS.

The cost estimate for CO CEMs provided in the Supporting Statement for the NESHAP for Industrial, Commercial and Institutional Boilers and Process Heaters at Major-Source of HAP12 is grossly underestimated. The estimate provided in this document was approximately $163,000 (total capital investment) per unit. However, based on our own estimates, this value is over $800,000. Below is a comparison of the itemized cost listed in Appendix J-2 of the CO cost estimate versus the commenters estimated cost. (see submittal for cost comparison table). :

Adjust the estimated costs for the CO CEMs installation and reevaluate its justification.

Response: See response for DCN EPA-HQ-OAR-2002-0058-2960.1, Excerpt Number 300.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 135

Comment: Production losses will be incurred under the provisions of this rule for process shutdowns associated with the burner tune-up requirements, CPMS calibration requirements, and special, uneconomic operations associated with the performance test requirements that must be done using worst case conditions. This production related cost must be taken into account in evaluating the proposed rule, not only from a cost perspective, but from a feasibility perspective. For example, annual emissions testing on all units using a 4 hour test run time will impose tremendous operational constraints on facilities that they may not even be able to meet. EPA should add this cost to its burden estimates.

Response: See response for DCN EPA-HQ-OAR-2002-0058-3213.1, Excerpt Number 15.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 146

Comment: EPA has estimated a cost of $44,000 to conduct testing for all 5 pollutants. While we believe this might adequately predict the cost of a stack test for some boilers, EPA has not considered scenarios where facilities must test two different operating conditions to represent "worst case" mercury and chloride inputs or where facilities do not have enough of their "worst case" fuel to complete testing in a 1 or 2 day period. The cost to complete stack tests for PM, dioxin/furan, and CO and fuel analysis for chlorine and Hg was estimated by EPA to be $16,000. As the dioxin/furan lab analysis is the most costly element of the stack testing required and eliminating the HCl and Hg testing only removes one sample train and associated stack tester, we do not believe this scenario would be less than half of the cost of stack testing for all 5 pollutants, and would likely be at least $30,000 in stack testing and fuel analysis cost. Even EPA's estimate for the Phase II ICR stack testing assumed $54,000 for most of the units tested with standard methods. Facilities required to conduct that testing found the costs to be considerably higher, with spot reports of at least $60,000 for a single series of tests. EPA should reexamine its estimated stack testing costs.

Response: See response for DCN EPA-HQ-OAR-2002-0058-3213.1, Excerpt Number 25.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 147

Comment: The Cost and Emissions Impact memo states that boilers and process heaters designed to burn liquid fuels are expected to conduct annual compliance tests for PM, dioxin/furan, and CO, but comply using fuel analysis for HCl and Hg. As the floor units for liquid fuels are based on uncontrolled light liquid units for HCl and Hg and are theoretically based on the average of emissions achieved by the top 12% of liquid units, we do not agree with the assumption that the remaining 88% of liquid fueled units will not need controls in order to comply with the HCl and Hg limits, especially since these limits were only based on data from less than 25 boilers. In fact, EPA's database that shows that several facilities burn fuel oil that may not meet the proposed emission limits for HCl or Hg based on fuel analysis. EPA should re-evaluate its compliance cost assumptions for liquid fuel boilers for HCl and Hg.

Response: The final rule allows any unit, not just units without controls, to demonstrate compliance with the applicable emission limit for hydrogen chloride or mercury using fuel analysis if the emission rate calculated according to §63.7530(c) is less than the applicable emission limit. We included estimates of control costs for all liquid fuel units where the estimated baseline emissions exceeded the MACT floor.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 228

Comment: Requiring the ERT will add time and cost to stack testing projects, as time will have to be spent entering the test data into the tool and then quality assuring the ERT output. We do not believe that EPA has included this extra cost in their analysis.

Response: See response for DCN EPA-HQ-OAR-2002-0058-3213.1, Excerpt Number 306.

Social Costs

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute and National Petrochemical and Refiners Association
Document Control Number: EPA-HQ-OAR-2002-0058-0851.1
Comment Excerpt Number: 5

Comment: The proposal preamble also reports that EPA has been unable to estimate the benefits of any HAP reductions that might be achieved by these requirements and thus they argue that the societal benefits of this proposal come from estimated reductions in criteria pollutants, in particular particulate matter (PM) reductions. It is a significant and questionable shift for the EPA to attempt to justify regulations under HAP reduction authority on another basis than HAP reductions. The CAA provides different authorities and different procedures for addressing criteria pollutants and HAPs. Congress established separate procedures to allow optimization of the requirements addressing these very different types of pollutants and to minimize the disruption to the economy by applying inappropriate approaches to each. Basing HAP rules on their estimated criteria pollutant impacts circumvents Congress's intent and the procedures for addressing criteria pollutants established by the CAA. The benefits associated with criteria pollutant reductions have already been claimed under the NAAQS rulemakings and procedures and it is inappropriate to claim the same benefits again. The benefits that EPA claims for fine PM reductions are highly uncertain and significantly over-estimated. [This issue is discussed at length in the American Chemistry Council Comments on EPA's Proposed Rule National Emissions Standards for Hazardous Air Pollutants From the Portland Cement Manufacturing Industry 74 FR, May 6, 2009, Submitted September 4, 2009 to Docket EPA-HQ-OAR-2002-0051.]

Response: 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. Co-benefits that occur as a result of a regulatory action are appropriate to include in the regulatory impact analysis, and it is appropriate to compare the total monetized benefits with the costs.

Commenter Name: Los Angeles Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1778
Comment Excerpt Number: 57

Comment: Those who benefit either economically or through the use of a product should be the ones that pay for that product. I should not be asked to subsidize the production of products for energy with my life or my health. When hazardous air pollutants are created that combine disposal or elimination, costs should be borne by those that benefit from the products.

Response: EPA acknowledges this comment, but a general discussion of who pays for the environmental externalities that occur from the creation of products is outside the scope of this specific rulemaking.

Commenter Name: Houston Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1876
Comment Excerpt Number: 72

Comment: Use EPA discretion to protect public health while avoiding unnecessary capital and operating costs. The estimated costs for the wood products industry, for the installation of control devices, is $6- to $7 billion. We must ensure that the benefits derived from this expenditure are real, and not just estimates by a panel of experts who vary widely on their estimates of benefits.

Response: The primary benefits estimates are derived from epidemiology studies examining two large population cohorts: the American Cancer Society cohort (Pope et al., 2002) and the Harvard Six Cities cohort (Laden et al., 2006). These are logical choices because both studies are well designed and peer reviewed. In addition, EPA estimated the range of benefits derived from an expert elicitation to characterize the uncertainty in the concentration-response function for premature mortality (Roman et al., 2008). In general, benefits estimates derived from the expert elicitation functions fall between results using the epidemiology studies.

Commenter Name: Houston Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1876
Comment Excerpt Number: 87

Comment: I think it can go without saying that often these things can go past the regulations that not everyone obeys the regulations; they do what they can to protect the bottom dollar, and in the long run, a healthy society will do more to -- without missing workdays or sick days -- sick days will do more for the economy than being allowed to burn more substances close to home.

Response: The rate of compliance with this rulemaking will be addressed through enforcement and compliance measures taken after this rule is finalized. The rate of compliance is outside the scope of comments relevant to the rulemaking. The health benefits to society, including missed workdays and missed school days, are addressed in the Regulatory Impact Assessment.

Commenter Name: Houston Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters

Document Control Number: EPA-HQ-OAR-2002-0058-1876
Comment Excerpt Number: 121

Comment: Further, EPA's cost discussion fails to analyze or calculate the full benefits of these rules to the public.

Response: An estimate of the health benefits anticipated as a result of this rule are provided in the regulatory impact analysis.

Commenter Name: Houston Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1876
Comment Excerpt Number: 162

Comment: It has always been my experience that the EPA doesn't take into account -- when the developing standards, they don't take into account costs, that --
the costs that have to be made. However, since it has
been brought up consistently throughout the day, I would
like to add to that discussion; birth defects, asthma,
bronchitis, heart attacks, cancer, premature death.
These are some of the outcomes of being exposed to the
air toxins that have been previously discussed, and I
would like to see how much that costs. There is a cost
associated with that.
Last week, I was asked to go visit a young
mother on the east end who lives next to a source that
has already been cited for releasing some of the toxins
previously mentioned. Because I spoke Spanish, they
asked me to go talk to her and try to explain to her why
her child was born with half a brain and suffered for
six months and died. I really didn't have an answer for
that.
All I could do was share her – her concern. She was also -- she was extremely upset, and I'd like to know how much that's worth. It was very
difficult speaking with her, her trying to take care of
her family, and still having two other children figuring
out how -- what she was going to do living next to -- to
the source, and if anybody was gonna do anything about
it. I didn't know what to tell her, but it did prompt
me to come and give a few comments today.

Response: EPA agrees that exposure to fine particulates and toxic air pollutants is associated with severe health effects and reducing exposure to these pollutants is associated with substantial public health benefits.

Commenter Name: Arlington Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1779
Comment Excerpt Number: 20

Comment: EPA's RIA estimates that the cost of the Boiler MACT proposal to the chemical industry of about 1.8 billion, which is less than half the ACC estimate of 3.8 billion. EPA also projects that about a quarter of the cost increase will be passed through to consumers.

Response: EPA has made revisions to its cost analysis in the final rule. See the RIA and the memorandum " Revised Methodology for Estimating Cost and Emissions Impacts for Industrial, Commercial, Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants – Major Source, January 2011"

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 10

Comment: In addition to the capital costs, EPA also estimates the "social costs" (e.g., those costs accruing to consumers and producers because of higher prices and diminished trade position). For example, the cost to the chemical industry will be about $500 million in 2013. EPA assumes that producers that comply with the boiler MACT will be able to pass along a quarter of the cost increase via higher prices. Because many products manufactured in the US face stiff global competition, it will be difficult to pass through costs except during times when the market is tight. EPA acknowledges that this will make US exports less competitive and provide opportunities for relatively less expensive imports, but their modeling shows these impacts to be modest (for example, a 0.02% gain in chemical imports and a 0.02% decline in chemical exports). Because many basic building block chemical products potentially affected by the Boiler MACT proposal do not have huge trade volumes (i.e., chlorine, ethylene, etc.), we do not believe EPA considered the subsequent impact in the derivative products that are most exposed to trade. If supply chains are disrupted, this could significantly amplify the impact.

Response: EPA acknowledges the comment, but the commenter did not provide specific information that could be used to conduct the suggested analysis.

Commenter Name: Matthew Todd and David Friedman

Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 198

Comment: It seems clear that there is little potential HAP reduction from a very high cost unfocused energy assessment program.

The EPA analysis attempts to justify the energy assessment requirements by citing the potential PM reductions that would presumably be achieved along with the HAP reductions. However, PM is regulated by section 110 of the CAA and has been addressed and is being readdressed under the process established by that portion of the Act. Should PM reductions be needed from boilers and process heaters that must be and is being addressed under the 110 authority and should not be a significant consideration here.

Recommendation: The energy assessment requirements should be deleted from the final rule.

Response: The final rule retains the energy assessment requirements. See the preamble for discussion of the final energy assessment. Refer to the RIA for a discussion of how criteria pollutants were used to estimate the benefits of this rulemaking.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 128

Comment: In addition to the capital costs, EPA also estimates the ‘social costs" (e.g., those costs accruing to consumers and producers because of higher prices and diminished trade position). For example, the RIA states that the cost to the chemical industry will be about $500 million in 2013. EPA assumes that producers complying with this rule will be able to pass along a quarter of the cost increase via higher prices. Because many products manufactured in the US face stiff global competition, it will be difficult to pass through costs except during times when the market is tight. EPA acknowledges that this will make US exports less competitive and provide opportunities for relatively less expensive imports, but their modeling shows these impacts to be modest (for example, a 0.02% gain in chemical imports and a 0.02% decline in chemical exports). Because many basic building block chemical products potentially affected by this proposal do not have huge trade volumes (e.g., chlorine, ethylene, etc.), we do not believe EPA considered the subsequent impact in the derivative products that are most exposed to trade. If supply chains are disrupted, this could significantly amplify the impact.

Response: EPA acknowledges the comment, but the commenter did not provide specific information that could be used to conduct the suggested analysis.

Commenter Name: Michael A. Livermore
Commenter Affiliation: Institute for Policy Integrity, New York University School of Law
Document Control Number: EPA-HQ-OAR-2002-0058-2720.1
Comment Excerpt Number: 13

Comment: The Regulatory Impact Analysis Should Include a Longer Time Horizon

EPA's regulatory impact analysis presents monetized benefits and annualized social costs for the year 2013 alone. Annualized social costs are based on estimates of annualized engineering-based compliance costs. Benefit estimates are based on emissions reductions in 2013 alone. Capital costs appear to be annualized over the life of the relevant investment at a 7% interest rate (20 years for major equipment, 2 or 4 years for items like fabric filters). The energy assessment is annualized over 5 years (although no justification is given for this). While this is an appropriate method for determining costs and benefits for 2013, it ignores several important longer-term issues.

For example, shutdown of existing units and increased numbers of new units are not accounted for. Shutdown of existing units due to the program would count as additional decreases in emissions and increased costs. Shutdown of units due to independent factors would not directly count as incremental decreases in emissions; however, this would result in spreading the compliance costs of these units over fewer years and fewer reduced emissions, and thus decrease the cost-effectiveness of the program. By contrast, the number of new units over time would probably add net benefits to the rule.

In addition to these sorts of effects, the short time horizon for the regulatory impact analysis ignores future cost decreases due to both innovation and learning, effectively freezing the cost estimates at current technology costs. With technological innovation, economies of scale, and learning, compliance costs may decrease with time. [Footnote: For example, fabric filters may cost $X right now, last two years, and generate $Y/year benefits. But as the regulation increases market share for the filters and incentivizes innovation, as the manufacturers learn more cost-effective filter production techniques, and as the polluters learn more cost-effective filter application techniques, in future years, maybe filters will only cost $1/2X and last for three years, but still generate $Y/year in benefits (or, possibly, $2Y, if the technology improves or if new applications have unexpected co-benefits).] Both the White House's Office of Management and Budget and the EPA's own Economic Analysis Guidelines stress the need to account for technological innovation and learning effects. [Footnote: WHITE HOUSE OFFICE OF MGMT. & BUDGET, CIRCULAR A-4 at 34 (2003); EPA, 240-R-00-003, GUIDELINES FOR PREPARING ECONOMIC ANALYSIS at 5-7(2008 external review draft).] In particular, the OMB's Circular A-4 advises agencies: "The time frame for your analysis should cover a period long enough to encompass all the important benefits and costs likely to result from the rule." [Footnote: CIRCULAR A-4, supra note 50, at 15.] Due to the short time horizon of its regulatory impact analysis, EPA may have underestimated the net benefits of various alternative policies.

Response: The timeframe for this analysis is consistent with other recent EPA analyses. For this rule, the net benefits far outweigh the costs even with several unquantified benefit categories.

Economic Impacts

Commenter Name: Ritchie Monteith
Commenter Affiliation: AbitibiBowater - Catawba Operations
Document Control Number: EPA-HQ-OAR-2002-0058-0849.1
Comment Excerpt Number: 1

Comment: The continued cumulative impact of EPA regulation is enormous and is putting our industry and many others at a cost disadvantage compared to our worldwide competitors.

The Boiler MACT as issued for AbitibiBowater – Catawba Operations alone will require capital expenditures of at least $20 - $40 million and annual operating costs will range from $4 million to in excess of $7 million.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2601
Comment Excerpt Number: 3

Commenter Name: Ritchie Monteith
Commenter Affiliation: AbitibiBowater - Catawba Operations
Document Control Number: EPA-HQ-OAR-2002-0058-0849.1
Comment Excerpt Number: 7

Comment: During the worst economic crisis since the Great Depression, this rule will impose an unsustainable regulatory burden.

The rule is more expensive than it needs to be, and will ultimately result in more mill closures and job losses.

Response: The rule is based on the requirements of the CAA.

Commenter Name: Houston Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1876
Comment Excerpt Number: 15

Comment: API/NPRA members have oil-fired boilers and heaters located in Hawaii, Alaska, and U.S. island territories, areas that do not have gas supplies available, where the option of switching to a different fuel does not exist. The overly stringent proposed standards for oil-fired units will likely mean that a number of existing boilers and heaters will have to be replaced with new units due to the infeasibility of retrofitting existing units with pollution control devices capable of achieving the proposed standards. We are operating in a business climate in which our members are evaluating their operation assets to determine whether they will remain economically viable. A regulatory mandate for significant capital investment to replace equipment and install new controls could well contribute to a decision to simply shut down some facilities.

Response: Standards have been revised, and a subcategory for non-continental liquid-fired units has been added to address some of the unique constraints faced by operators of these units.

Commenter Name: Houston Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1876
Comment Excerpt Number: 143

Comment: We are very concerned that these proposed rules are far more restrictive than needed to protect the environment. Industry cost estimates for compliance with these rules is in the range of $20 to $50 billion and significantly higher than EPA's cost estimates. These high costs, at a time when the nation is recovering from the recession, are not sustainable and will result in further loss of high-quality manufacturing jobs in the United States as companies close or relocate offshore.

Response: The rule is based on the requirements of the CAA.

Commenter Name: Houston Public Hearing Transcript

Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1876
Comment Excerpt Number: 146

Comment: We are also evaluating costs for compliance with the other Boiler MACT proposed limits. In addition to the $32 million we already spent, our preliminary information indicates that Luke will need to invest another $14 and a half million to ensure compliance with proposed Boiler MACT limits. These costs are very significant for my mill and will put us at a disadvantage not have to comply with these requirements. I am concerned that these additional costs will impact our ability to compete successfully in a global marketplace.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2418.1
Comment Excerpt Number: 4

Commenter Name: Adam Hoffman
Commenter Affiliation: Flambeau River Papers
Document Control Number: EPA-HQ-OAR-2002-0058-1754.1
Comment Excerpt Number: 1

Comment: I am an employee of Flambeau River Papers in Park Falls, Wisconsin, and I am very concerned that the new Boiler MACT rules could cost me my job. We are a small company that is struggling to compete against foreign competitors and large corporations. Our mill not only supports me and my family, it is the lifeblood of our rural community. If the cost of compliance for the Boiler MACT causes our mill to shut down, this entire region in Northern Wisconsin will suffer.

In 2006 our mill was shut down for several months. At that time it was difficult for most people to find good jobs. Now, with the current state of the economy, loosing even more good paying manufacturing jobs would be devastating. Also, if our mill is shut down, the paper that we produce will more than likely be replaced in the market by foreign manufactures who are not held to high environmental standards.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2418.1
Comment Excerpt Number: 4

Commenter Name: Adam Hoffman
Commenter Affiliation: Chequamegon School District Board of Education
Document Control Number: EPA-HQ-OAR-2002-0058-1847.1
Comment Excerpt Number: 1

Comment: I am a member of the Chequamegon School District Board of Education, and I am concerned about the impact of the proposed Boiler MACT rules on the education of the students in our school district. The Chequamegon School District is located in rural Northern Wisconsin. The economy in our community is supported by Flambeau River Papers, which employees over 300 people, and impacts hundreds of other jobs in the region.

If the Flambeau River Papers mill cannot afford to comply with the Boiler MACT rules, or is not able to comply because the limits are unachievable, the mill will end up going out of business. If this happens, many families will end up moving out of the area, because there are not enough jobs available to cover this loss. This will result in our school seeing a significant decline in student enrollment, which will significantly reduce our state financial aids. School districts across our state already have to make cuts to stay afloat. If our state aids are decreased even more, we will be forced to make significant programming cuts. Because of this, the education of the students left in our district is going to suffer.

I am sure that this scenario will play out in many communities across the nation. Please consider that the impact of these regulations reaches much further than just "cleaning up the environment." None of us want our children breathing "bad" air. However, please consider the emotional and psychological stress that a child goes through when their parents lose their jobs. Also, consider the impact on the children who are left in a community that was once supported by a strong, good paying manufacturing facility.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2418.1
Comment Excerpt Number: 4

Commenter Name: Mark Petty
Commenter Affiliation: Flambeau River Papers
Document Control Number: EPA-HQ-OAR-2002-0058-1753.1
Comment Excerpt Number: 1

Comment: My family is currently employed at Flambeau River Papers LLC in Park Falls Wisconsin, and I am very concerned that Boiler MACT would substantially increase compliance costs for our mill and could put my job and my coworkers' jobs at risk and the community that relies on these jobs – at risk. Our mill has firsthand experience with a closure as it was closed for several months in 2006 with devastating impacts not only to those of us that lost our jobs but also to the local economy. You can clearly see in the workers eyes as they worry about their families and what's next after a life at the mill. Other good paying jobs are hard to find in our rural communities so the harm lasts a long time if not forever. Not only will the town suffer but outreached communities that supply wood to the mill such as loggers and saw mills.

My family lives near the mill and I want them safe, don't get me wrong. Over the years, I have seen the mill get much better environmentally by making changes for the good. The mills new ownership is definitely for a better environment. Equipment and practices we have are helping make us a greener facility in our community. Also, I'm proud to work at a mill that produces a green product that is made from local renewable forests. You go in stores these days and it's hard to find things made in America anymore – we need American products supporting good manufacturing jobs.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2418.1
Comment Excerpt Number: 4

Commenter Name: Caroline Dauzat
Commenter Affiliation: Rex Lumber
Document Control Number: EPA-HQ-OAR-2002-0058-1845
Comment Excerpt Number: 1

Comment: I am writing this in response to the proposed rules for major source Boiler MACT. The rules you are proposing are not achievable. It will cause great hardship to our industry and most likely cause the closure of many sawmills. In Florida alone, the estimate for capital expenditures in the forest products industry is over $170,000,000. We are located in rural small towns in the panhandle of Florida and soon rural Mississippi. The closure of our plants will be devastating on each of these local economies, losing over 125 jobs per location, that is a total loss of 375 jobs. Small towns need these jobs. We are one of the few manufacturing industries that still successfully operate in the United States, is the point to get rid of us too?

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2601
Comment Excerpt Number: 3

Commenter Name: A. Daniel White
Commenter Affiliation: T.R. Miller Mill Company, Inc

Document Control Number: EPA-HQ-OAR-2002-0058-1597.1
Comment Excerpt Number: 2

Comment: The forest products industry has struggled in the past four years to survive the crash of the housing market. Over 130 sawmills have closed during this period. T. R. Miller and our 220 employees have been hanging on by the narrowest of margins. We simply cannot afford increased costs from absurd, unnecessary, and probably unachievable emissions limits.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2418.1
Comment Excerpt Number: 4

Commenter Name: Houston Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1876
Comment Excerpt Number: 2

Comment: Our initial evaluations of the proposed rules indicate the cost impacts will be a serious challenge to most of the current running mills. The cost impacts hit just as the economic conditions might otherwise allow facilities that currently are shut down to restart. For example, extreme costs may prohibit restarting some of our wood-product facilities that were curtailed due to impacts of the recession on the housing market. This result -- this result would be opposite to the administration goals of rebuilding jobs. It would be a devastating blow to the families and the communities dependent on these facilities.
In fact, to give these costs some scaled perspectives, the Wood Products Council, in which we are members, compiled a projected cost to comply with the proposed rules for some 34 broilers at forest product industry facilities in the State of Mississippi where my mill is located. Those costs projections totaled $290 million. And incredibly, that amount is more than a quarter of the total forest product industry's profits in 2008 and 2009 in the U.S.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2601

Comment Excerpt Number: 3

Commenter Name: Charles McRae
Commenter Affiliation: Rex Lumber
Document Control Number: EPA-HQ-OAR-2002-0058-1846
Comment Excerpt Number: 4

Comment: Explain the potential impact on your facility. Possible closure and job loss. Cheaper to purchase natural gas boiler, but that increases costs and you become uncompetitive.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2418.1
Comment Excerpt Number: 4

Commenter Name: Houston Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1876
Comment Excerpt Number: 10

Comment: In our area in Alabama where it's 16.4
percent unemployment, and in Mississippi, we're at
12.3 percent unemployment. We survived, Scotch Plywood
did, and we have rehired and we're back in full
production. We contributed to the safe -- we think --
environmental responses in a responsible manner. We
have complied with the plywood MACT and now we're faced
with the Boiler MACT.
Our estimate of costs is going to be
somewhere in excess of $2 million to comply as the
Boiler MACT is presented today. Waynesboro, Mississippi
will have to spend around a half a million dollars and
increase our costs -- our guess, best guess -- is two
and a half percent. That doesn't seem like much.
That's a small number, two and a half percent, but our
margins are small, and nonexistent the last year and a
half, the other way.
So we're forced to look at other
decisions. The decisions for us is pretty simple.
We'll make this investment, which will exceed $2 million
at the two facilities in the current -- or our best

estimate of the future economic environment, and we make
partial investments and run economically at a reduced
rate at both facilities or close our facilities.
So as we look at that, B and C cause us to
lay off personnel significantly impacting our local
communities. Unemployment nationally is 9 and a half
percent; we're in excess of 12 to 16 percent. We will
get back to the housing starts, economically, we will,
but we'll -- or we're going to regulate ourselves out of
being competitive. That's the question that we -- are
we going to continue to have our production capacity to
our neighbors to the south, South America?

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2601
Comment Excerpt Number: 3

Commenter Name: Los Angeles Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1778
Comment Excerpt Number: 15

Comment: We cannot afford to spend $1.5 million on new control technology on one boiler.
The expenses that this rule would create go directly to our bottom
line. These rules are -- these are not expenses we can
pass onto our customers. This rule will increase our
costs and make us less competitive in the marketplace.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2418.1
Comment Excerpt Number: 4

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute and National Petrochemical and Refiners Association
Document Control Number: EPA-HQ-OAR-2002-0058-0851.1
Comment Excerpt Number: 17

Comment: Where the outage and/or cost associated with trying to meet these limits are excessive or the proposed limits cannot be achieved by any means, (this is a real possibility, because the assumed controls are not demonstrated to be effective on gas fired sources) the units and their associated processes will be shutdown and jobs lost. The impact of lost jobs and economic activity is not reflected anywhere in the record.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-3193
Comment Excerpt Number: 1

Commenter Name: Houston Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1876
Comment Excerpt Number: 22

Comment: At the end of the day, we've heard a lot about jobs or costs to industry. Here in Houston, we understand that very well. We hear it every time a regulation is proposed, every time a standard is strengthened, we hear about jobs, but I think there's also a very clear understanding amongst those that actually bear the burden of pollution in this region, that eventually those costs will get passed on to regular citizens.
6And the choice is not between having those costs or not having those costs; it's how those costs will be borne, and I don't think the EPA needs to have another hearing to ask citizens whether they would prefer to bear those costs in increased health expenditures or increase to consumer goods. I think the choice is clear, and I think the EPA is of finally starting to get that, that we need to protect public held to the maximum, that we need to lead industry to innovate, to figure out ways to add control measures that reduce energy use, but also reduce air emissions. And at the end of the day, folks will pay those higher costs for their consumer goods, but they'll be able to do so from a point of view where their -- where their health has been protected, and I think everybody in this region would much prefer to spend a little more on their consumer goods and spend a lot less on their -- on their health expenditures.

Response: Thank you for your comments.

Commenter Name: Houston Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1876
Comment Excerpt Number: 25

Comment: MR. DeLaCRUZ: My name is Ricardo De La Cruz, and I am from Edinburg, Texas. I'm a member of the Pulp and Paper Research Council and I have worked at International Paper for the past 25 years. Here we make corrugated board which is made into corrugated boxes. These are used to package citrus produce to tomatoes televisions, et cetera.

We have two containers and a sheet plant in the county of Hidalgo, Texas. In total, our plants provide 200 green jobs in our county. Many mills around the country with good and safe linerboard supply us. If these mills were to shut down on the impact of the border MACT rules, we would be forced to get our linerboard from China or South America. We have testimonial that the linerboard is tainted with mercury or lead. The American public would not like to have these products packaged in these containers which contain mercury or lead.

Last week, we received a box made in Mexico with linerboard from China and no one wanted to touch it for the fear it was tainted with mercury or lead. Do we want this product coming into the United States? This is the effect of the ruling of MACT and what it would hold.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2418.1
Comment Excerpt Number: 4

Commenter Name: Houston Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1876
Comment Excerpt Number: 27

Comment: The proposed Boiler MACT rule would hit the Coastal community very hard economically. Coastal's cost to comply might approach $40 million of capital costs, which would be a tough pill to swallow for a company that is in a super-competitive, low-margin industry, and whose annual sales is only $200 million. Additional annual operating and maintenance costs could approach $2 million a year. Fortunately, Coastal is one of the best performers in the industry and would probably figure out a way to stay in business. However, I can assure you that many companies in our industry, most of whom have lost millions of dollars over the past three or four years, would choose to simply stop the bleeding and shut down.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2601
Comment Excerpt Number: 3

Commenter Name: Los Angeles Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1778
Comment Excerpt Number: 35

Comment: EPA needs to look realistically at the economic impacts of these proposals. And I just add that many of our facilities in the forest products industry are in rural areas where manufacturing family-wage jobs are hard to find. And so we're a major part of a vital and green economy in rural areas. We've been challenged by the recession, which has impacted our industry dramatically. We've lost 350,000 jobs in the industry in total. Some will say we're crying wolf on jobs. I think I can confidently say that these rules, as they're proposed, you're going to find more plant closures.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2601
Comment Excerpt Number: 3

Commenter Name: Houston Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1876
Comment Excerpt Number: 38

Comment: The forest products industry is a very significant business in Texas, particularly in the eastern quarter of the state, and in 44 counties of deep East Texas we have three -- the three remaining paper mills are located in deep East Texas. They employ 3,500 workers directly, and the industry is as a whole employs about 54,000 workers across the state, and I think we heard from one of those this morning from a box plant in the valley.
The industry is distributed throughout the state. It is dependant upon the East Texas forest for its raw materials and is a rural industry and an industry that is not concentrated largely in industrial areas of the state. And so I wanted to point out, that as the rules stand, they could have significant impact on rural economies, because it's not -- not a ship-channel issue for the forest projects industry.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2601
Comment Excerpt Number: 3

Commenter Name: Houston Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1876
Comment Excerpt Number: 41

Comment: The proposed Boiler MACT rule could strike a severe blow to the manufacturing economy and is far more than is needed to protect our environment. The cost to individual mills could be tens of millions of dollars in additional capital expenditures, which may not be sustainable given the down the economy and fierce international competitiveness. No other country in the world is imposing requirements like these putting U.S. manufacturers at a competitive disadvantage.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-3193
Comment Excerpt Number: 1

Commenter Name: Houston Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1876
Comment Excerpt Number: 43

Comment: Given the jobless nature of the economy recovery, the rulemaking will add excessive burdens to the expense of the manufacturing workers. The total capital costs just for the forest products industry alone are estimated at about $7 billion, and the costs for all manufacturing could be between $20 to $50 billion. A wide range of sectors and the jobs they sustain would be severely harmed.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-3193
Comment Excerpt Number: 1

Commenter Name: Houston Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1876
Comment Excerpt Number: 48

Comment: Boiler MACT, as proposed, would cost the forest products industry billions of dollars and MeadWestvaco tens of millions of dollars over the next two to four years. These new investments could mean job losses in the United States and could force production to be moved to countries where the environmental standards are much lower than our current practices.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2601
Comment Excerpt Number: 3

Commenter Name: Los Angeles Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1778
Comment Excerpt Number: 56

Comment: Overall, we believe Boiler MACT and the other boiler rules are too restrictive. It will place an enormous burden on manufacturers. It will impose unjustified limits that will impose a large unnecessary economic burden on the country. And the EPA has an opportunity to modify these requirements while being faithful to the legal obligation.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-3193
Comment Excerpt Number: 1

Commenter Name: Los Angeles Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1778
Comment Excerpt Number: 62

Comment: To position the mill for the future, earlier this year we announced plans for a proposed 650,000-pound-per-hour biomass boiler. If the project moves forward it would support our goals to use biomass-based energy, improve efficiencies and solidify the long-term viability of the company. The electricity generated by the boiler would qualify as green power and displace fossil fuels. We are working toward approval of this project by the end of this year.
The proposed Boiler MACT rules would be cost prohibitive for our company. As defined today, the equipment needed to meet the proposed limits would easily kill the project. Additionally, our existing boilers would have to remain in service. These are older units with higher emissions and would incur a very high burden to try to reduce their emissions to

retrofit.
In the state of Washington the cost to
our industry is estimated at $210 million. The proposed
rule would be devastating to the forest industry as a
whole. This is an industry that employs more people
nationwide than automotive or chemical industries.
Across the U.S., Boiler MACT would impose a monetary
burden of 6 to $7 billion on the forest products
industry as well.
Comparatively, the industry has only
profited $1 billion over the last two years. It's not
very hard to see that that sort of imbalance from a cost
to improvement ratio is hard to sustain. It is not logical to us to require a
company with solid environmental performance, in a
industry known to be based on renewable resources, to
comply with the rule as currently written. If the new
rule goes into effect in its current form, the EPA is
putting jobs in our community and business in general at
a great risk. It would impose extremely costly controls
where there is no real environmental or health benefit.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2418.1
Comment Excerpt Number: 4

Commenter Name: Houston Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1876
Comment Excerpt Number: 70

Comment: The Regulatory Impact Analysis does not accurately measure
the impact on smaller plant facilities. By combining
all plant facilities together, the conclusions drawn do
not represent the economic impact to smaller operations.
The cost of capital investment to install control is
disproportionate when comparing a facility that
generates $100 million in annual revenue to a facility
that may only generate $50 million in annual revenue.
The equipment cost is -- the equipment cost does not
correlate to revenue and the ability to absorb the
capital cost is a disproportionate penalty to the
smaller plants. The Impact Analysis contains only data

through 2007 and thus ignores the most devastating impact on shipments, employment, and other operating parameters by not including the worst years of this recession, which have been 2008 and 2009. If one looks at the capacity utilization chart, Figure 2-15 in the RIA, one can visually see that the elimination of 2008 and 2009 data will skew the data and impact any conclusions drawn from it.

The criteria used to classify an "establishment" as large versus small is based on number of employees. This is not a good methodology, in my opinion, since some manufacturing processes are labor intensive and others are highly automated. Production capacity and emissions volume do not necessarily correlate to facility employment.

The collapse of a new housing markets and the recessionary decline in the U.S. economy has severely impacted the wood products industry. I would estimate that 35 to 40 percent of the industry capacity has been curtailed or shut down. These regulations will further reduce the probability of many of these facilities restating when economic conditions improve.

In addition, I would predict that the economic cost of complying with these new regulations will cause new closures as small privately held sawmills and plywood operations and other wood products businesses come to the conclusion that trying to sustain an operation that has had multi-year losses is simply not a good decision. These closures will disproportionately impact rural lower income communities.

In our business, lumber prices have fallen 31 percent since the peak in 2005. It will be difficult to rationalize the cost of installing additional control equipment when that capital does not produce any benefits to the business, and in fact will make U.S. producers less competitive against off-shore suppliers from Brazil, Chile, and China. No other nation in the world has the environmental costs that we have in the United States.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2418.1
Comment Excerpt Number: 4

Commenter Name: Houston Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1876
Comment Excerpt Number: 74

Comment: Some interest groups will characterize my comments as a typical strategy of crying "poor man" when faced with new environmental regulations and costs. After suffering multiyear losses, the smaller privately held business -- businesses are in fact poor.
To those who would attack my comments as a typical business reaction, I would invite them to walk in my shoes with the responsibility of trying to sustain a company in the worst economic conditions of the past 70 years and maintain good paying jobs with good benefits for over 1,000 families.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2418.1
Comment Excerpt Number: 4

Commenter Name: Houston Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1876
Comment Excerpt Number: 79

Comment: Our industry is like any other industry struggling to recover. Our forest products industry has been struggling to recover from the recession. Our unemployment rate is still lingering around 10 percent.
The Clean Air Act rule was recently announced -- specifically, Boiler MACT -- could be unsustainable for much of the U.S. manufacturing processes, and also, the very high paying jobs that it provides, unless there can be some greater flexibility allowed in meeting these targets.
The Boiler MACT would require installation of up to four different air pollution control devices, and those would serve -- conflict, in some cases, with

some of our existing controls. The cost to individual plants, such as the one that I work at, would be -- could be as much as tens of millions of dollars in additional capital, which may not be sustainable, given the economic downturn and the fierce international competition. And let me just say that. The fierce international competition.
No other country in the world is imposing requirements like these, which puts -- which makes a very unlevel playing field for us. It puts us at a huge competitive disadvantage. Across the forest products industry, these rules could cost anywhere from $6- to $7 billion over the next two to four years when the industry itself only made a fraction of that over the last two years.
This would result in the severe hardships, and something that I'm very passionate about, could cost tens of thousands of job losses in the forest products sector alone. And given the cost of other likely environmental programs, the compound effects of the -- the compound effects in job losses would be much larger in a sector that's lost 350,000 jobs since the downturn began in 2006. It's much greater than that when you go back to 2001 and 2002.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2601
Comment Excerpt Number: 3

Commenter Name: Houston Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1876
Comment Excerpt Number: 92

Comment: Since the '70s, the government has taken a big step to increase air quality, in general, right? In every step that they've taken, the business community has come out and said that we're gonna lose thousands of jobs, it's going to ruin our business, in all of its stuff like that, and really, it hasn't -- like there hasn't been an economic downturn that you can really blame on environmental regulations. The economy is, though, a lot more flexible and able to accept environmental

regulations in general, and in businesses are a lot more flexible than they realize.
I mean, I -- it's just tougher for them to make changes so when -- when looking to make -- to change these rules, just keep that in mind when they come out here and tell you it's gonna ruin our business, we're going to -- thousands of people are going to be unemployed. If you look at the past, that really hasn't happened on a consistent basis.

Response: The EPA analysis for this regulation indicates that production and employment changes are likely to be small. Many of the predictions of large employment changes and closures are based on a lack of market flexibility.

Commenter Name: Houston Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1876
Comment Excerpt Number: 93

Comment: EPA's proposed rules will create serious disincentives for the use of biomass and alternative fuels and thereby increased use of fossil fuels, which we believe is counterproductive and contrary to the country's energy interests. The rule will have undeniable economic consequences. The forest products industry has projected new equipment required under the proposed rules will cost more than $6 billion over a three-year compliance window plus billions more in subsequent years for operating maintenance expense. Those capital costs alone exceeds industry profit of recent years.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2601
Comment Excerpt Number: 3

Commenter Name: Houston Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1876
Comment Excerpt Number: 102

Comment: The Pulp and Paper Resource Council (PPRC) logged over 255 curtailments with mill closures in 2009, on our Web site, pprc.info. On the May 2010 unemployment report just released, the rate of 9.7 percent
unemployment is facing our nation. Our manufacturing facilities do not need this new financial burden placed on them by these new proposed EPA rule changes. There are 23 forest products boilers and 115 more boilers across the great State of Texas. With the proposed changes, the protected cost to change these boilers to meet the new proposed rules are estimated at $1.89 billion just for Texas alone.

Boiler MACT will set emissions limits for hazardous air pollutants from gas, liquid, or solid-fuel fired boilers and process heaters located at universities, in small municipalities, food product processors, furniture makers, federal facilities and a wide range of manufacturers, not just the forest products industry. The EPA's proposed Boiler MACT is so stringent that it will result in significant and unnecessary job losses if finalized in its current form. it would impose extremely costly controls even where there is no significant environmental or health benefits, which is contrary to the direction Congress provided in the Clean Air Act.

5The paper and forest products industry currently employs nearly 900,000 workers. The forest products industry has lost some 350,000 additional -- or 350,000 additional jobs since the beginning of the downturn in 2006, 100,000 jobs lost last year alone. Approximately 75 mills have closed in the last five years. These mill closures were not due to Boiler MACT but the economy and foreign competitors. China is one of the major players and they are not held to the same rigorous environmental standards these American companies are. We need a level playing filed. The entire U.S. paper industry only made $1 billion in the last two years.

This imposed -- this imposed cost will cut more American jobs. The PPRC believes that the forest products industry will be greatly affected. Most of the paper companies across our nation are in rural areas of the states where the backbone of our nation has an agricultural base. We do not need to see these forest products jobs go away. We need to keep America working because we are American workers trying to survive. With these new costs coming so close on the heels of the recent economic downturn, the would be unavoidable and severe financial distress and economic disruption for the workers, families, and communities for whom paper and wood products companies are the primary, or the only economic engine. My mill boasts a payroll of $70 million and more than $4 million is paid annually in property taxes, which mainly benefit the local school districts. There are sales taxes in excess of $909,000 and approximately $350 million spent in vendor supplier-wood relationships.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2601
Comment Excerpt Number: 3

Commenter Name: Houston Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1876
Comment Excerpt Number: 104

Comment: The forest and paper products industry were green even before there was a label for being green. We have had green jobs for over a century, but only until recent years has there been a "buzzword" for being environmentally responsible. The forest products industry will always be the best environmental stewards of our forest and land. We are sustainable, renewable, and the greenest. We do not want our jobs, livelihood, and communities destroyed by your legislated rules that bring about unintended consequences of jobs lost. Your unintended consequences of stringent rules will put more mills on our map out of business. There are American workers' names that go with the numbers on our map [see map provided as supplemental information to transcript]. The hourly workers are almost always the first to go. The PPRC urges you to "Seek a Balance"
between the environment and industry.

Response:
See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2601
Comment Excerpt Number: 3

Commenter Name: Houston Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1876
Comment Excerpt Number: 127

Comment: The rule will substantially increase compliance costs. The proposed changes come at a time when mill closures/curtailments have reduced OSB board production by nearly 50 percent. Regulations that do little to improve the environment eventually threaten jobs and can lead to permanent rather than temporary closures.
And I close on a personal note. Norbord has two OSB mills in Texas; one located in Nacogdoches, the other at Jefferson. Within the past three years, Norbord has invested over $10 million at each location on PCWP MACT improvements. Unfortunately, the Jefferson mill was closed indefinitely January 2009 due to economic conditions (our products are used directly in the housing industry). One hundred employees lost their jobs. The decision to re-opening this mill will be measured against several factors, not the least of which would be additional capital investment to meet more stringent environment standards.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2601
Comment Excerpt Number: 3

Commenter Name: Houston Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1876
Comment Excerpt Number: 134

Comment: We are in the process of reviewing and conducting detail site-specific engineering review to determine the Boiler MACT compliance costs for NewPage. However, preliminary cost estimates for NewPage indicate capital expenditure of greater than $100 million, and potentially several million dollars in additional annual operating costs for these facilities. These costs are

significant and will put NewPage at a distinct
disadvantage as we compete in a global marketplace with
other paper producers located in jurisdictions that do
not have to comply with these requirements. EPA needs
to be including flexibility options that allow for
alternate compliance approaches.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2418.1
Comment Excerpt Number: 4

Commenter Name: Houston Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1876
Comment Excerpt Number: 163

Comment: I'm a huge believer in -- everyone needs a job. I do realize the economy, that
everyone needs to make a living. I'm a big believer in
the ingenuity of the American businessman. Usually,
what made this country great, and I truly believe that
if you set that bar however you set it, they're going to
meet it, and they're going to make a profit. That is
what makes America great. And -- and I'm sure they'll
be able to do it, and -- and do it well. And everywhere
it's been my experience, and research has shown, where
there is a good environment, there's always a good
economy. Bad environment, always -- is -- is bad -- bad
economics at the end of the day.

Response: Thank you for your comments.

Commenter Name: David Meeker
Commenter Affiliation: National Renderers Association
Document Control Number: EPA-HQ-OAR-2002-0058-1868.1
Comment Excerpt Number: 1

Comment: The proposed rules (referred to herein as the "Boiler MACT" or the "Rules") set stringent emission limits for hazardous air pollutants from industrial, commercial, and institutional boilers that combust fossil fuels and biomass. Because of the broad sweep of the Rules and ultra-low emissions levels they impose, even for boilers using relatively clean fuels like natural gas and processed fats, we are concerned about the negative impacts of them – both economically and technologically. In terms of the economic burden, the capital cost expenditures are estimated to be in the tens of billions of dollars at thousands of facilities across the country. This is more burden than industry can bear in these economically challenging times. A wide range of sectors and the jobs they sustain would be severely harmed – universities, small municipalities, food product processors, furniture makers, federal facilities, and a wide range of manufacturers and other businesses that operate gas, liquid, or solid-fueled fired boilers.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-3193
Comment Excerpt Number: 1

Commenter Name: Randy Lilburn
Commenter Affiliation: Sierra Pacific Industries
Document Control Number: EPA-HQ-OAR-2002-0058-1883.1
Comment Excerpt Number: 1

Comment: I am greatly concerned over EPA's proposed Boiler MACT rule and the implications therein that would significantly burden, and have the potential to limit or close operations at our existing boiler and cogeneration facility. The continued effect to provide steam or electricity to our industry via non-wood/biomass only add cost burden and dependence on fossil and foreign fuels -both of which further limit the viability of the wood-products industry.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2418.1
Comment Excerpt Number: 4

Commenter Name: Fred L. Taylor
Commenter Affiliation: Troy Lumber Company
Document Control Number: EPA-HQ-OAR-2002-0058-1879
Comment Excerpt Number: 1

Comment: Troy Lumber Company's facility includes a saw mill, a planer mill, two (2) boilers, and two (2) lumber drying kilns. Our facility processes Southern Yellow Pine logs into finished lumber. Our industry has been in a 10 year squeeze on our profit margins. We pay more for the logs than in the past yet get less for the lumber than any time in our long history. We have over 100 employees and offer them a competitive salary and full benefits. This proposed regulation will have a devastating effect on our facility as well as our suppliers and our customers. Many wood-related businesses in North Carolina will simple cease to exist if they have to upgrade their air pollution control devices from cyclones to bag houses or electrostatic precipitators and to install continuous opacity monitors. In our small, poor, rural, economically depressed county this measure could effectively double our unemployment rate. This is due to the cost to purchase, install and operate the new equipment which has not been proven to accomplish the goals the new rules prescribe.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2418.1
Comment Excerpt Number: 4

Commenter Name: Chris Williams
Commenter Affiliation: Steely Lumber Company
Document Control Number: EPA-HQ-OAR-2002-0058-1875.1
Comment Excerpt Number: 2

Comment: Across the forest products industry, these rules could cost $6 to 7 billion over the next two to four years. This will result in severe hardship and thousands of job losses in the forest products sector. The costs to individual mills could be tens of millions in additional capital expenditures.

I am writing representing Steely Lumber Co., Inc., a family-owned southern pine sawmill company that has been in business since 1896 and currently employs close to 90 people. We currently operate two wood byproduct fired boilers that just barely go over the threshold for this new rule. We operate and comply to TCEQ regulations, but this new MACT rule would likely cost us near $2 million dollars to comply with. This is a hit that we could not recover from. This would force us to consider new alternatives to dry lumber and would likely put us out of business. I strongly suggest the EPA reevaluate the proposed rule.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2601
Comment Excerpt Number: 3

Commenter Name: Arlington Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1779
Comment Excerpt Number: 2

Comment: We believe EPA has significant discretion in the MACT program to protect public health while avoiding the unnecessary burdens these proposed regulations could impose. Boiler MACT could cost the forest products industry alone over $6 billion in capital expenditures and hundreds of millions more in annual costs unless significant changes are made.

We are coming out of the worst economic recession since the Great Depression, and the forest products industry has lost over 350,000 jobs in the last three years. To be a sustainable industry supporting high-paying jobs and providing sustainable products, we need sustainable environmental regulations.

Otherwise, costs of this scale will force further mill closures and tens and even hundreds of thousands s of additional job losses, especially given other expected, significant environmental regulatory costs.

Exports will drop, and imports will increase since no other county is contemplating requirements this extreme.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2601
Comment Excerpt Number: 3

Commenter Name: David A. Buff
Commenter Affiliation: Golder Associates
Document Control Number: EPA-HQ-OAR-2002-0058-1841.1
Comment Excerpt Number: 3

Comment: Indeed, if bagasse boilers were to be placed in a subcategory with other types of boilers (e.g., boilers that have low CO
emissions which cannot be matched by any existing bagasse boiler), then many of the existing boilers
would have to be shut down or replaced. This would have disastrous economic and operational impacts
on the sugar industry.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2601
Comment Excerpt Number: 3

Commenter Name: David Meeker
Commenter Affiliation: National Renderers Association
Document Control Number: EPA-HQ-OAR-2002-0058-1868.1
Comment Excerpt Number: 4

Comment: EPA can provide reasonable approaches in its proposed Rules that will improve air quality and target investments where they are most needed while preventing severe job losses and billions of dollars in unnecessary regulatory costs.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-3193
Comment Excerpt Number: 1

Commenter Name: Randolph Price
Commenter Affiliation: Consolidated Edison Company of New York
Document Control Number: EPA-HQ-OAR-2002-0058-1869.1
Comment Excerpt Number: 7

Comment: CECONY also operates some steam system boilers on residual oil in areas of New York City where the natural gas infrastructure is insufficient to provide natural gas in quantities capable of firing these boilers. Although it is the largest district steam system in the United States, the CECONY system only serves approximately 1,800 municipal, institutional, commercial, and residential customer accounts. The cost of wide-scale gas system improvements of a magnitude sufficient to fire these steam system boilers would be prohibitive over this limited customer base.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2418.1
Comment Excerpt Number: 4

Commenter Name: Arlington Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1779
Comment Excerpt Number: 21

Comment: Because many basic chemical companies face stiff global competition, it will be difficult to pass through costs except during times when the market it tight.

Raising the cost of capital will also impact future investment and job growth in high-paying manufacturing jobs, further slowing the economic recovery of the chemical industry.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2601

Comment Excerpt Number: 3

Commenter Name: Arlington Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1779
Comment Excerpt Number: 48

Comment: The NAM is the leading voice for the manufacturing economy in Washington, D.C., which provides millions of high-wage jobs in the U.S. and generates more than $1.6 trillion in GDP. In addition, 80 percent of NAM members are small businesses which serve as the engine for job growth.
The EPA's proposal to impose more emission standards on industrial boilers will cut across all sectors of the NAM membership, including the chemical, auto, metalworking, petroleum refining, and forest and paper sectors. New standards for industrial boilers will have an immediate impact on our members' bottom line.

Manufacturers are attempting to fully recover from the steepest economic downturn since the 1930's and bring back the 2.2 million high-wage jobs lost during the previous recession. Federal policymakers should create conditions that will lead to economic expansion and not stifle the vitality necessary to create jobs and technologies that will continue to improve the nation's air quality. Imposing stricter mandates on the manufacturing sector will not accomplish any of these objectives.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2601
Comment Excerpt Number: 3

Commenter Name: Arlington Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1779
Comment Excerpt Number: 50

Comment: While there are aspects of the proposed rules that the NAM supports, our overriding concern is that compliance costs associated with the more stringent Boiler MACT rule will hinder manufacturers' ability to add jobs as the recovery attempts to gain more attraction.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-3193
Comment Excerpt Number: 1

Commenter Name: Arlington Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1779
Comment Excerpt Number: 70

Comment: The total benefits far outweigh the costs of cleaning up. EPA estimates that the cleaner air from cutting emissions from major sources will save nearly 18 billion to over 43 billion each year beginning in 2013. Total capital costs for installing equipment on all of these boilers is estimated to range from 10.5 billion to 12 billion with total amounts for operations, maintenance, and other requirements of 3.9 billion.

Response: Thank you for your comments.

Commenter Name: Arlington Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1779
Comment Excerpt Number: 88

Comment: During the worst economic crisis since the Great Depression, this rule will impose an unsustainable regulatory burden.

This rule is more expensive than it needs to be and will ultimately result in more mill closures and job losses.

Response:
See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-3193
Comment Excerpt Number: 1

Commenter Name: Arlington Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1779
Comment Excerpt Number: 91

Comment: I joined the Pulp and Paperworkers Resource Council over 10 years ago when I saw American jobs leaving at an alarming rate. We’re hourly workers from competing companies, working together as brothers to save our jobs. The economy, higher fiber and energy costs added to the need for a profit, combined with increasing regulatory costs, can be the nail in the coffin. Creating new jobs is a must, but don't get rid of the remaining jobs we have left.

Our company is a leader in sustainability and has been for generations. We support efforts to protect the environment and have voluntarily worked to reduce emissions in our manufacturing operations. Together with other leaders in our industry, paper and forest products manufacturers have reduced air pollution from our operations by more than 50 percent in the past 20 years.

As you know, the industry is one of the most heavily regulated in the United States. It harms our ability to compete with manufacturers in countries that do not share our commitment to environmental performance. Despite this burden, new regulations, such as the Boiler MACT, continue to be proposed that would require additional investment with no substantial environmental benefit.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2601
Comment Excerpt Number: 3

Commenter Name: Arlington Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1779
Comment Excerpt Number: 95

Comment: Just in Virginia these regulations could impose an additional one billion in capital cost for manufacturers, increasing operating costs, and actually decreasing energy efficiencies. These monies spent to comply with this regulation would not substantially improve our air quality but will cost us jobs and future growth investments. We cannot afford to limit our ability to compete in the global marketplace by layering additional costly regulations on our manufacturing.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2601
Comment Excerpt Number: 3

Commenter Name: Arlington Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1779
Comment Excerpt Number: 96

Comment: It is our concern that if Boiler MACT continues in its present form, the American forest products industry and the communities it supports will ultimately meet the same fate.

Our nation’s recent economic down turn has not been very kind to the forest products industry. In the past two years, our industry’s profits were approximately $1 billion. Over 40 mills closed, and another 150 had to take idled down time. Tens of thousands of high-paying jobs have been lost, and the way of life as we knew it has drastically changed. The capacity of these mills has been shifted to emerging overseas’ markets such as China and Brazil, where companies can operate with little or no environmental or labor regulations.

If these current standards are implemented, the cost to an already struggling industry will be devastating. As I have previously stated, our industry’s profits were approximately $1 billion. And that is for our whole industry, not just Smurfit-Stone Container -– the whole industry was $1 billion. For the past two years that’s about what we made.

To meet these new standards and be EPA compliant, our industry will have to spend approximately 6 to $7 billion, and this could be the final blow to the American forest products industry, forcing our companies to close their doors, move their operations overseas. When this happens, we will not only have lost a high-paying, tax-generating jobs that help support our country, we will also be multiplying the very same emissions that we are trying to control in the first place, causing the American people to lose all the way around.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2601
Comment Excerpt Number: 3

Commenter Name: Arlington Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1779
Comment Excerpt Number: 98

Comment: In 2009 our Number 3 paper machine was shut down due to economic downturn. As a result of this shutdown, some 110 people were out of work for about a year. But it’s not just the mills that are affected; there is a ripple effect on the jobs in the community as well. There are 4 to 10 jobs related to every one job at the mill. As a result, many other families were affected during the machine’s downtime as well. Thankfully, this machine is back up and running in 2010, and most of the workers are back on the job. These jobs are so important to rural areas where median wages so very low even with mill workers’ salaries figured in.

I’ve painted you the picture of where I work and what we face, but there is a much larger picture. The paper and forest industry employs nearly 900,000 workers. The forest products industry has lost more than 350,000 jobs since the beginning of the downturn in 2006 –- a hundred thousand of these jobs last year alone. Approximately 75 mills have been closed in the last five years.

These mill closures were not due to Boiler MACT but the economy and foreign competition. China and Latin America are the major players and are not held to the same rigorous environmental standards as American companies face. We need a level playing field. The entire paper industry made only one billion dollars in the last two years, as you previously heard. The cost of Boiler MACT in the State of Georgia alone is going to be somewhere around $520 million, and across the industry in the next two to four years could be 6 to $7 billion.

The proposed Boiler MACT rule could damage the manufacturing sector's ability to recover during these hard economic times and is far more restrictive than needed to protect the environment.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2418.1
Comment Excerpt Number: 4

Commenter Name: Arlington Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1779
Comment Excerpt Number: 109

Comment: The standards for new boilers are so stringent that boiler manufacturers cannot guaranty compliance, which will assuredly stifle investment in new systems that feed economic growth.

The total capital costs for the forest products industry alone are estimated around 7 billion for the next two to four years, which I heard mentioned earlier. And the cost for all manufacturing could be 20 to 50 billion. Those are huge numbers.

In Michigan and West Virginia, the states where SFK has operations, the boiler MACT costs for the forest products industry are expected to be approximately 270 million and 20 million, respectively. Those numbers are staggering by themselves, but take into account that the entire forest products industry only made one billion dollars in each of the last two years.

This will result in severe hardship and tens of thousands of job losses in the forest products sector alone. Given the cost of other likely environmental programs, the compounded effects will result in hundreds of thousands of job losses in a sector that lost 350,000 jobs since 2006.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2601
Comment Excerpt Number: 3

Commenter Name: Arlington Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1779
Comment Excerpt Number: 113

Comment: As proposed, EPA's combination of four rulemakings is diametrically opposed to supporting U.S. industrial competitiveness and domestic job growth. Without considerable change, it appears these rules will seriously undermine U.S. employment growth and economic recovery.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-3193
Comment Excerpt Number: 1

Commenter Name: Arlington Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1779
Comment Excerpt Number: 120

Comment: In my position I often hear the comment, are they trying to regulate business out of this country. And our business has been cut in half over the last couple years as we are tied directly to the housing market. And we're also under increased pressure from the regulatory side from both OSHA and the EPA. And these new regulations do come at a price, despite what many of the speakers, I believe, felt here today. Industry does not have unlimited resources and funding.

Regulations such as this put a heavy burden on industry and will drive many manufacturers out of business and to other counties.

I urge you to, strike a balance with these regulations and work towards a cleaner environment but help us stay in business and stay in the country.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-3193
Comment Excerpt Number: 1

Commenter Name: Thomas Ratzlaff
Commenter Affiliation: City of Park Falls, WI
Document Control Number: EPA-HQ-OAR-2002-0058-2350.1

Comment Excerpt Number: 1

Comment: I am very concerned that Boiler MACT would substantially increase compliance costs for one of the City of Park Falls' major employers, Flambeau River Papers, LLC. Increased costs could put our mill and the jobs that our community relies upon at risk.
The City of Park Falls has firsthand experience with mill closure. In 2006 the owners of the Park Falls paper mill filed for bankruptcy, and the mill was closed for several months with devastating impacts not only to those who lost jobs but the entire local economy.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2418.1
Comment Excerpt Number: 4

Commenter Name: Thomas McInvale
Commenter Affiliation: Keadle Lumber Enterprises, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2007.1
Comment Excerpt Number: 1

Comment: The proposed Boiler MACT rules, if adopted, present a potential financial impact that very likely could result in the closing of business and loss of jobs to nearly 100 people living in an area with an average unemployment rate of 13%. The closure of Keadle Lumber Enterprises would have a far reaching impact in the loss of revenue to area businesses, loss of tax revenue to federal, state and local governments, and the negative impact of one more empty manufacturing facility in a once thriving community. The potential costs of controls proposed while being exorbitant, will not necessarily meet limits and will most likely result in the abandonment of Biomass fueled boilers in favor of cheaper natural gas boilers. These natural gas boilers will increase costs to the facility making an already depressed industry even less competitive in the market place.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2418.1
Comment Excerpt Number: 4

Commenter Name: Charles Thomas III
Commenter Affiliation: Shuqualak Lumber Co., Inc.
Document Control Number: EPA-HQ-OAR-2002-0058-1758
Comment Excerpt Number: 1

Comment: We have four wood fired boilers at our facility and if these rules are enforced, it will shut us down! We are located in one of the poorest counties in the United States. In fact, we are one of the few remaining industries in our county. These proposed rules will eliminate 105 direct jobs and approximately 800 indirect jobs. I strongly disagree with the proposed rules due to the fact that the rules as proposed are unachievable. Our government is encouraging the increased use of biomass fired boilers at the same time that the proposed rules will completely eliminate them.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2418.1
Comment Excerpt Number: 4

Commenter Name: Ardis Almond
Commenter Affiliation: Almond Brothers Lumber Company
Document Control Number: EPA-HQ-OAR-2002-0058-2349.1
Comment Excerpt Number: 1

Comment: Millions of dollars worth of pollution equipment to every boiler would be the final blow to an already battered industry. Many, many, sawmills have been shut down for sometime, due to the awful housing market. I can give you a perfect example of one. There is another mill in our small rural town. It has been shut down for almost 3 years, now, and its 100 employees laid off. That company has diligently kept two employees working keeping their equipment greased, tested, and maintained for an expected start up at the first opportunity. That company had hopes of starting back up near the end of the year. I know they, now, can't even consider it with the Boiler MACT proposal facing them. How can they start up a mill when they can barely afford to do so under the best of circumstances, much less, when they will have to put out millions before they put the first employee back to work?

Here is another personal example from our operation: We have barely survived through the recession and for most of last year ran only 30 hours per week. We were able to survive primarily because we are an export mill cutting lumber for world markets and were not as damaged by the housing bust. (We are one of the good guys, helping the trade deficit.)

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2601
Comment Excerpt Number: 3

Commenter Name: Jim Hickman
Commenter Affiliation: Langdale Forest Products Co.
Document Control Number: EPA-HQ-OAR-2002-0058-2065.1
Comment Excerpt Number: 1

Comment: We are deeply concerned that the potential impact of pending Clean Air Act regulation could be unsustainable for U.S. manufacturers and the high-paying jobs they provide. It appears that EPA has little appreciation for unintended consequences that would punish manufacturers, particularly in the forest products industry, during these difficult economic times.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2601
Comment Excerpt Number: 3

Commenter Name: Tyler McShan
Commenter Affiliation: McShan Lumber Company
Document Control Number: EPA-HQ-OAR-2002-0058-2207
Comment Excerpt Number: 2

Comment: In today's completive market, disposing of unused biomass or switching to another fuel would not be feasible. We could not compete and would have to shut down.
The only jobs in Pickens County in the private sector are in forest products or raising and processing chickens. After 4 generations for raising trees, a renewable source of building products and fuel for renewable energy, I would hate to have to try raising chickens. Not only would our 58 employees be out of work, but the people who cut and haul logs to our mill and our lumber from it would have to find something else to do as well.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2418.1
Comment Excerpt Number: 4

Commenter Name: Ashley Peterson
Commenter Affiliation: American Meat Institute
Document Control Number: EPA-HQ-OAR-2002-0058-2382.1
Comment Excerpt Number: 2

Comment: In terms of the economic burden, the capital cost expenditures that would be necessary to comply with the Rules are estimated to be in the tens of billions of dollars at thousands of facilities across the country. A wide range of sectors and the jobs they sustain would be severely affected – universities, small municipalities, food product processors, furniture makers, federal facilities, and a wide range of manufacturers and other businesses that operate gas, liquid, or solid-fueled fired boilers. Imposing such an economic burden on industry is substantial and would threaten the viability of some companies, particularly in these economically challenging times.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2601
Comment Excerpt Number: 3

Commenter Name: R. Wade Mosby
Commenter Affiliation: The Collins Companies
Document Control Number: EPA-HQ-OAR-2002-0058-2351.1
Comment Excerpt Number: 5

Comment: The effect of these four proposed rules is that they threaten the viability of these three facilities (Chester, CA, Lakeview OR and Kane, PA) that include 3 sawmills, a biomass power plant and a hardwood dimension plant.I urge you to please consider alternative rules that will avoid the impact these proposed rules will have on my (The Collins Companies) three facilities. Our plants are an important part of our countries timber infrastructure and renewable power portfolio. These three rural communities cannot stand further family wage job losses that would result from the promulgation of this rule.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2418.1
Comment Excerpt Number: 4

Commenter Name: Don Grimm
Commenter Affiliation: Hood Industries, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2352
Comment Excerpt Number: 13

Comment: The rationale that supports the proposed approach for the Gas 1 subcategory applies equally well to biomass boilers and, therefore, provides ample support for adopting work practices instead of numeric emissions limitation for biomass boilers. For example, in the forest products industry alone, the estimated cost of complying with the proposed HAP emissions limitations for biomass boilers is $3.3 billion. This is an extraordinary cost that, in the context of the forest products industry, equals or exceeds the magnitude of the economic burden that EPA predicts for the Gas 1 subcategory. Similarly severe economic impacts are expected in other industry sectors where biomass boilers are widely use, such as the furniture, sugar, and agricultural products industries. Thus, there is strong economic justification for prescribing work practice standards for biomass boilers in lieu of numeric emissions limitations.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2601

Comment Excerpt Number: 3

Commenter Name: Tim Keneally
Commenter Affiliation: KapStone Paper and Packaging Corporation
Document Control Number: EPA-HQ-OAR-2002-0058-2673.1
Comment Excerpt Number: 1

Comment: KapStone's main concern with the proposed Industrial Boiler MACT is the proposed standards are far more stringent than needed to assure protection of health and the environment from industrial boiler HAP emissions and do not strike a balance with economic health of the effected sources. As described in detail below, KapStone is committed to operating in an environmentally responsible and sustainable manner. The pulp and paper industry faces a withering global economic slump and fierce competition from overseas manufacturers. Therefore, it is imperative for mandatory environmental controls such as the Industrial Boiler MACT standard to be tailored as closely as possible such that health and the environment are protected without requiring unnecessary expenditures of time and resources.

Response:
See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2418.1
Comment Excerpt Number: 4

Commenter Name: Jay Galloway
Commenter Affiliation: Tolleson Lumber Company
Document Control Number: EPA-HQ-OAR-2002-0058-2452.1
Comment Excerpt Number: 1

Comment: As our company, together with the entire wood products industry, struggles to recover from the worst downturn in decades, the potential impact of the Boiler MACT rule may drive companies as ours out of business.
It is our belief that to comply with the proposed rule, we need to spend an estimated $8,000,000 to $10,000,000 in direct capital expenditures. This is more than we have spent on capital improvements over the last 5 years combined! Moreover, compliance would require estimated additional operating expenses close to $2,000,000 per year. We do not believe that the housing market (the main market for our products) can support such a cost increase, so the possibility of us closing down is very real. Tolleson Lumber Company has been in existence since 1919 and currently employs 280 people. At full capacity we employ 380.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2418.1

Comment Excerpt Number: 4

Commenter Name: J.R. Randy Bush
Commenter Affiliation: Virginia Forest Products Association
Document Control Number: EPA-HQ-OAR-2002-0058-2402.1
Comment Excerpt Number: 1

Comment: Virginia's forest products industry is one of the State's largest manufacturing activities. A recent government sponsored economic study1 shows that forestry and agriculture comprise the largest economic segment of the Commonwealth, with forestry contributing $23 billion annually in total economic impact while providing jobs for 144,000 Virginians. Forests are the largest land use in the State, covering 62% of Virginia's land mass, and forest products related economic activity is found in every county and city of the Commonwealth.
Of the boilers initially identified in Virginia that would be impacted by this regulation, nearly half are attributable to paper, solid wood, or furniture manufacturing. It is estimated that through this regulation just the paper and solid wood boilers alone will have a capital cost of $230,000,000 ... with all impacted boilers in Virginia facing a potential capital cost of $930,000,000. And this is just for Virginia, nationwide the potential cost is over $18 billion! Recent economic conditions have placed a severe toll on the industry ... easily the worst since the Depression, with many facilities closing their doors either temporarily or permanently. As an example, studies have shown the number of sawmills in the State in 2009 is one-half of the total found in 1999, just 10 years previous. Any additional regulatory burdens placed on the industry, particularly those that have questionable cost vs. benefit ratios, will put many more facilities at risk.

A single unifying theme lies at the heart of our comments on the proposed Industrial Boiler MACT standard – the proposed standards are far more stringent than needed to assure protection of health and the environment from industrial boiler HAP emissions. As stated earlier, the membership of the Virginia Forest Products Association faces a withering global economic slump and fierce competition from overseas manufacturers. Therefore, it is imperative for mandatory environmental controls such as the Industrial Boiler MACT standard to be tailored as closely as possible such that health and the environment are protected without requiring unnecessary expenditures of time and resources.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2601
Comment Excerpt Number: 3

Commenter Name: Claude Audet
Commenter Affiliation: Boralex, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2387.1

Comment Excerpt Number: 1

Comment: Boralex owns six biomass electrical generating facilities in the US. Five are located in Maine and one in upper state New York. All are located in rural areas that provide a source of job opportunity to local residents and service related businesses. Each facility provides a significant tax base to the communities they reside in. Boralex provides over $75M annually to purchase processed biomass fuel, perform facility maintenance, pay employee salaries and to pay federal, state & local taxes, mostly in Maine and New York State. [See submission for list of Boralex facilities] Since 2004, Boralex has invested over $54 M into its biomass generating facilities to improve efficiencies, upgrade emission control devices and to maintain plant operating integrity. [See submission for capital investments to-date.]
Boralex continues to make substantial investment into the operations of its five operating biomass power plants. These plants provide good-paying jobs and benefits directly to over 150 people working at these facilities. Fuel procurement (fuel processing and transportation) provides an additional 400 jobs. Boralex contributes significantly to both local and state economies through taxes paid, fuels, equipment and consumables purchased and employment of area contractors during scheduled maintenance shutdowns. Operation of these facilities is being accomplished at a time when competition for energy sales is very aggressive, prices for renewable generation are low and the cost of operating biomass-fired power plants is substantial. The current limits imposed in the proposed MACT rule are going to present a significant and very costly challenge to Boralex. If the rule is implemented as written, Boralex could very well be faced with a decision to defer plant operations at their biomass electrical generating facilities, permanently close these facilities, or possibly relocate them out of the US.
As this tragedy unfolds, the economic well being and future of at least 500 people, either working directly to operate the Boralex biomass facilities or indirectly as fuel suppliers or other support services, along with countless others in Maine's biomass energy sector and over 18,000 people working in the biomass energy industry across the US will be placed in jeopardy. All those depending upon the success of this industry will be placed in the throes of a situation imposing unrealistic, unattainable and very costly demands, with insignificant environmental, health or societal benefit, while placing the collective futures of our employees and this industry in grave peril of extinction.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2418.1
Comment Excerpt Number: 4

Commenter Name: Randy Thurman and Brent Stevenson
Commenter Affiliation: Arkansas Environmental Federation and Arkansas Forest & Paper Council
Document Control Number: EPA-HQ-OAR-2002-0058-2719.1
Comment Excerpt Number: 1

Comment: The memberships of the AEF and AFPC are concerned about the proposed Boiler MACT rule —the Maximum Achievable Control Technology rule for industrial, commercial and institutional boilers and process heaters — that was published June 4, 2010. Arkansas is in the midst of severe economic distress, as is the rest of the nation. Since June 1995, Arkansas has lost nearly 100,000 manufacturing jobs, roughly 40 percent of that sector's employment. The proposed Boiler MACT will stymie economic recovery for many industrial sectors, particularly for the forest products sector.

That sector employs over 29,000 workers, primarily in the south Arkansas area. In fact, the forest products sector is the single largest driver of the economy in south Arkansas, and has itself suffered serious decline in recent years due to foreign competition, market pricing and lack of product demand as the housing market has tanked. The added burden of compliance with the Boiler MACT proposed rule will, without a doubt, cost Arkansas jobs and investments. As one mill owner noted recently, environmental compliance costs in the forest products sector cannot be passed through nor is there a return on the investment. It is a direct cost that will replace planned efficiency upgrades and expansions.
The impact of the MACT is not limited to large wood products companies however. Costly regulatory burdens under Boiler MACT will be felt by municipalities, universities, government facilities, and commercial entities. It has been estimated that costs to these entities in Arkansas alone will total $490 million, with roughly $390 million borne by the wood products sector.

We understand that the Boiler MACT rule alone could impose tens of billions of dollars in capital costs at thousands of facilities across the country. As EPA develops a final Boiler MACT rule, the AEF and AFPC strongly encourages the Agency to consider the impact of the MACT on the economy of our struggling state, investments and jobs.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2601
Comment Excerpt Number: 3

Commenter Name: Jay C. Moon
Commenter Affiliation: Mississippi Manufacturers Association
Document Control Number: EPA-HQ-OAR-2002-0058-2690
Comment Excerpt Number: 1

Comment: It is important to consider that manufacturers are attempting to fully recover from the steepest economic downturn since the 1930s and bring back the 2.2 million high-wage jobs lost during recent years. MMA strongly urges federal policy makers to create conditions that will lead to economic expansion and not stifle the industrial and manufacturing vitality necessary to create jobs and technologies that will continue to improve the nation's air quality. Imposing unduly strict mandates on the manufacturing sector will not accomplish any of these objectives.

New and overly stringent standards for industrial boilers will have an immediate impact on our members' bottom line without demonstrated environmental benefits. Compliance costs associated with these harsh and inflexible proposed rules will cost U.S. manufacturing jobs and hurt global competitiveness, just as the economic recovery attempts to gain more traction. .

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2601
Comment Excerpt Number: 3

Commenter Name: Bruce Braswell
Commenter Affiliation: Marsh Furniture
Document Control Number: EPA-HQ-OAR-2002-0058-2528
Comment Excerpt Number: 1

Comment: The US home construction industry is at near depression levels of business. Businesses that support the construction of housing in the US are dramatically impacted by the events that have unfolded since ~2007. Regulations requiring expensive control devices will further drive business off-shore to business friendly countries. Our facility, while a Title V Major source of VOC's from finishing operations, has a small wood fired boiler (19MMBtu/h) used to provide comfort and process heat. This water tube boiler was exempted under the 2004 Boiler MACT. Under Section E of the Preamble, EPA admits "We could not identify better HAP emissions reduction approaches that could achieve greater emissions reductions of HAP than the control technology combination (fabric filter, carbon injection, scrubber, and GCP) that we expect will be used to meet the MACT floor level of control". The regulation, as written, will probably result in many in the industry making a decision to shut down or move off-shore.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2418.1
Comment Excerpt Number: 4

Commenter Name: Charles R. Faulds
Commenter Affiliation: Texas Electric Cooperatives, Treating Division
Document Control Number: EPA-HQ-OAR-2002-0058-2526.1
Comment Excerpt Number: 2

Comment: Under the proposed rules, facilities could spend millions of dollars on controls and still not meet emission standards. The additional costs will be passed on to consumers and the producer is no longer competitive. Production and jobs for many facilities could be relocated to foreign countries where little concern for the environment exists and will cause a greater detriment to the environment and our economy than burning legitimate fuels in properly functioning boilers.

Response: First part is cost question: will what is costed meet the standard
The EPA used a standard market analysis to analyze the proposed MACT standards. The approach uses a single period multimarket partial equilibrium model to compare pre-policy market baselines with expected post-policy market outcomes. The analysis' time horizon is the intermediate run; some production factors are fixed and some are variable and is distinguished from the very short run where all factors are fixed and producers cannot adjust inputs or outputs. The intermediate time horizon allows us to capture important transitory stakeholder outcomes. Key measures in this analysis include industry-level changes in price levels, production and consumption, jobs, international trade, and social costs (changes in producer and consumer surplus). The analysis shows market responses with a very small increase in imports and a small job change.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 2

Comment: The boilers operated at Forest Products facilities are already regulated by a variety of environmental programs, and face even further regulation by additional programs being considered by EPA. The additional regulatory programs being considered by EPA will significantly increase capital and operational costs for the Forest Products Industry and jeopardize the long term viability of a healthy forest products industry (see Cumulative Burden White Paper – Appendix B).
AF&PA has studied the possible cumulative cost burden on forest products industry mills from the following regulatory actions, as illustrated in Appendix C:
* Boiler MACT revisions (for major HAP sources);
* Boiler GACT (for area HAP sources);
* CISWI revisions/new non-hazardous solid waste definition;
* Reopening other MACT standards for the pulp and paper and wood products sectors
* Regulation of hydrogen sulfide under section 112:
* Potential future inclusion of industrial boilers in CAIR;
* Lowering of NOx, SO2, and ozone NAAQS;
* Lowering and full implementation of the PM2.5 NAAQS; and
* Additional retrofit controls to enable states to meet reasonable further progress milestones under the Regional Haze Rule.

The cost burden for our facilities with industrial boilers, if all of these regulatory actions occur, could be $16.5 billion in capital over the next three to eight years and $1.7 billion in annual operating costs, for a total annualized cost of $3.7 billion. This represents four times the annual profits for the forest product industry the last two years. The anticipated control retrofits under the revised Boiler MACT are expected to comprise almost half of the cost impact. This analysis did not include the potential impact of the recently finalized PSD Tailoring rule which ignores the long standing principle of carbon neutrality and, like Boiler MACT, will discourage the use of biomass whether at existing boilers or new biomass boilers and potentially reverse the trend in the forest product industry's increasing energy production from biomass. A report entitled "Cumulative Cost Burden Analysis of Air Regulations Potentially Impacting the Forest Products Industry", which outlines the details of this tremendous burden of Clean Air regulations, is included in Appendix D.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2601
Comment Excerpt Number: 3

Commenter Name: Raymond J. Nutting
Commenter Affiliation: County of El Dorado Air Quality Management District
Document Control Number: EPA-HQ-OAR-2002-0058-2713.1
Comment Excerpt Number: 2

Comment: The implementation of the proposed MACT will result in a shutdown of many existing biomass plants throughout California and prevent construction of new facilities. The AQMD Board urges USEPA to review and modify the proposed unattainable MACT standards to assure the final rule is sustainable and protects the environment and public health without creating severe economic hardship.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2601
Comment Excerpt Number: 3

Commenter Name: Paul S. Dickens
Commenter Affiliation: Evergreen Packaging
Document Control Number: EPA-HQ-OAR-2002-0058-2696.1
Comment Excerpt Number: 3

Comment: Evergreen Packaging is working hard to sustain and grow our business and contribute to the nation's economic recovery. With unemployment figures hovering around 10%; federal, state, and local governments struggling to maintain fiscal stability; and severe limitations on capital project financing; it is difficult to imagine a more inopportune time for EPA to be imposing such a costly rule.
Evergreen Packaging supports efforts to address serious health threats from air emissions and believes EPA can craft regulations that sustain both the environment and our competitive position in the world marketplace, while maintaining jobs for the more than 4000 US-based

employees of our company. Unfortunately, implementation of EPA's proposed Boiler MACT, as currently proposed, will work at odds with efforts to build and maintain an economically sustainable future.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2418.1
Comment Excerpt Number: 4

Commenter Name: Haley Barbour
Commenter Affiliation: State of Mississippi, Office of the Governor
Document Control Number: EPA-HQ-OAR-2002-0058-2601
Comment Excerpt Number: 3

Comment: Because of the costly control devices that would have to be installed, the pending Boiler MACT policy could restrict resources for potential investment and hiring, therefore, jeopardizing the future of the manufacturing industry and its important role in the state's economy.

The repercussions of the Boiler MACT rule would touch other key groups in the state as well. From businesses, local governments, and government research entities to universities and commercial facilities, the cost under Boiler MACT in Mississippi, alone, has been estimated at $360 million.

This rule would have far-reaching effects, costing billions of dollars for manufacturers and other groups in states throughout the country. Although I am certainly a proponent of reducing the health risks associated with toxic air emissions, I believe we must do so in a way that upholds the sustainability of the market. I urge you to consider alternative approaches that protect the health of our people and accommodate the critical need for jobs.

Response: The EPA used a standard market analysis to analyze the proposed MACT standards. The approach uses a single period multimarket partial equilibrium model to compare pre-policy market baselines with
expected post-policy market outcomes. The analysis' time horizon is the intermediate run; some production factors are fixed and some are variable and is distinguished from the very short run where all factors are fixed and producers cannot adjust inputs or outputs. The intermediate time horizon allows us to capture important transitory stakeholder outcomes. Key measures in this analysis include industry-level changes in price levels, production and consumption, jobs, international trade, and social costs (changes in producer and consumer surplus). This analysis was done on the national level for many reasons. Impacts on price level, international trade, national production, and jobs could not have been estimated if the analysis focussed on regional or state levels. EPA also does not have the necessary data to estimate impacts on individual

states. Even if EPA had the data a detailed estimate of individual state and industry responses would be beyond the scope of what could be accomplished for this analysis.

Commenter Name: Joe O'Rourke
Commenter Affiliation: F.H. Stoltze Land and Lumber Co
Document Control Number: EPA-HQ-OAR-2002-0058-2418.1
Comment Excerpt Number: 4

Comment: The proposed MACT standards for Major Source boilers as well as Area Source boilers would be highly detrimental to our business too. The cost to comply with these new, stringent standards would jeopardize our ability to continue in business. That in turn would negatively affect our employees, our contractors, our suppliers, and the local and regional community. AF&PA has estimated that these new rules would cost the wood products industry $6 to $7 billion dollars over the next four years. In our own State of Montana, they estimate that there are seven Forest Products in operation, and that it would cost $60,000,000 in capital costs to bring those boilers into compliance with the new MACT standards. That works out to an incredible $8,500,000 per boiler. Don Wolf, of Burns & McDonnell Engineering Co. of St. Louis confirms this when he says "…the average capital cost of retrofitting biomass-fired boilers will be nearly $5 million". Furthermore, he estimates that "…air-pollution-control retrofit projects/fuel-switching projects can take 18 months to three years from the start of compliance planning through engineering and construction to startup." Our company has struggled mightily over the last several years to survive the severe economic downturn. Our business simply could not bear an added expense of that magnitude.

Response: The EPA used a standard market analysis to analyze the proposed MACT standards. The approach uses a single period multimarket partial equilibrium model to compare pre-policy market baselines with expected post-policy market outcomes. The analysis' time horizon is the intermediate run; some production factors are fixed and some are variable and is distinguished from the very short run where all factors are fixed and producers cannot adjust inputs or outputs. The intermediate time horizon allows us to capture important transitory stakeholder outcomes. Key measures in this analysis include industry-level changes in price levels, production and consumption, jobs, international trade, and social costs (changes in producer and consumer surplus). This analysis was done as a national analysis for many reasons. Impacts on price level, international trade, national production, and jobs could not have been estimated if the analysis focussed on individual entities. EPA also does not have the necessary data to estimate impacts on individual entities because much of it is proprietary. Even if EPA had the data a detailed estimate of individual entity responses for so many entities in so many sectors would be beyond the scope of what could be accomplished for this analysis.

Commenter Name: Timothy Hunt

Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 9

Comment: The bulk of the capital investment will be skewed toward the initial year. Industry incurs those costs in real time and they may be high enough that it could trigger a decision to pull out of the US market, thus costing jobs. Raising the cost of capital will also impact future investment and job growth in high paying manufacturing jobs further slowing the economic recovery of the manufacturing sector.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2601
Comment Excerpt Number: 3

Commenter Name: Kevin Bilbrey
Commenter Affiliation: Clarke County Pole and Piling Co, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2414.1
Comment Excerpt Number: 12

Comment: We must state that our company would be unable to afford the cost of installing the level of controls required to comply with the proposed emission limits. We would be forced to close our facility which currently employs 27 people and provides thousands of dollars in tax revenue to the surrounding community.

Response:
See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2418.1
Comment Excerpt Number: 4

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 30

Comment: AF&PA engaged Fisher International Inc. to assess the impact of the estimated compliance costs related to Boiler MACT and other upcoming air regulations on the economic viability of U.S. pulp and paper mills (see report in Appendix G). To estimate the impact of new air pollution control regulations on the U.S. pulp and paper industry, they used Fisher Solve, a proprietary industry database describing the assets and costs-of-production of each mill, and the estimated costs of controls that would likely be required for each mill to comply with the proposed Boiler MACT. Fisher projected the costs of compliance for each mill and calculated them as a percentage of the mill's costs of production. When compliance would increase a mill's cost-of-production by more than a sustainable amount, they listed that mill and its associated employment as being "at-risk." The results show that the Boiler MACT regulations alone, if they are incremental to the other pending manufacturing-related air regulations, would result in the closure of 30 mills employing 16,888 people or 14% of total employment at pulp and paper mills.

The pulp and paper mill jobs that would be at-risk due to air regulation changes support jobs in other industries that supply the pulp and paper industry and in local communities and throughout the U.S. due to the re-spending of worker incomes. A scholarly paper prepared by the Economic Policy Institute -- "Updated Employment Multipliers for the US Economy, 2003" -- was provided to Fisher by AF&PA. Table 9 of that paper indicates that for every 100 jobs in the paper industry, there are an additional 325 jobs sustained in other industries due to the purchase of supplies and the re-spending of worker incomes. Hence, the multiplier works about to 4.25. Applying the 4.25 multiplier to the job losses projected suggests that 72,000 jobs can be lost by imposing the proposed boiler MACT regulations (16,888 X 4.25 = 71,774).

Boiler MACT (and other potential upcoming Clean Air regulations) will adversely impact the sustainability of the forest products industry. Given foreign competition and the capacity of production, prices for various forest products (pulp, paper and wood products) are determined by world markets. In fact, the US share of paper capacity is declining and expected to continue to decline relative to emerging paper producing countries such as China [see submittal for chart showing global paper capacity]. Therefore, increases in production cost due to complying with overly stringent Boiler MACT limits (that exist due to inappropriate data, calculation, and technology assumptions) will not be able to be passed along to customers but instead borne by the mill or company. In the last two years, forest product industry profits have averaged just one billion dollars so absorbing twice that amount for a single new regulation ($1.7 billion) reinforces the conclusions of the Fisher International Inc. costs for Boiler MACT compliance and resulting job loss analysis.

The forest product industry and especially the pulp and paper sector is very capital intensive. Over the last fifteen years, the industry has failed to return its cost of capital (see submittal for chart showing costs of capital and returns over time) which in part has lead to many mill closures (over 150 in the last decade) and could prevent the ongoing viability of many more. This negative financial situation adds to the urgency of carefully assessing the magnitude of any new capital obligations through environmental regulations. Where there is discretion, and we believe the Clean Air Act provides as much as outlined below, EPA should embrace more reasonable emissions limits that reflect the variability of best performer boilers and avoid controls for threshold pollutants where risks are shown to be acceptable.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2601
Comment Excerpt Number: 3

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 31

Comment: The Forest Products Industry is a vital component of many communities across the United States, and our facilities are essential to the sustainability of these towns, providing a critical tax base and many jobs in a green industry. Forest Products facilities must compete in a global market with energy costs being one of the top three contributors to overall manufacturing costs. As the industry faces multiple regulations affecting our boilers and process heaters, it is imperative that we consider regulatory alternatives that balance cost, operational flexibility, and environmental impacts.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-3193
Comment Excerpt Number: 1

Commenter Name: Arnold Schwarzenegger
Commenter Affiliation: Governor Arnold Schwarzenegger
Document Control Number: EPA-HQ-OAR-2002-0058-2697.1
Comment Excerpt Number: 1

Comment: California's 40 biomass plants provide approximately 800 megawatts of electricity generation capacity that last year produced 5,700 gigawatt-hours of electricity, representing about three percent of California's total in-state power generation. In addition, these facilities employ 750 people on-site and support 1,200 to 1,500 jobs in the fuel supply infrastructure. I know the Obama Administration is working as hard as we are to increase, not eliminate, green jobs.

While I support your efforts to adopt national regulations to reduce hazardous air pollutants, I have significant concerns that these proposed standards would have adverse impacts on California's environment and economy. Therefore, I strongly urge you to reconsider the proposed standards for existing biomass-to-energy facilities.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2601
Comment Excerpt Number: 3

Commenter Name: David A. Buff

Commenter Affiliation: Golder Associates Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2801.1
Comment Excerpt Number: 1

Comment: The sugarcane processing industries in Florida, Texas, and Hawaii began over 100 years ago. In the 1980s, there were seven mills and 30 bagasse boilers operating in the industry in Florida, and a similar number in Hawaii. Currently only four mills and 15 bagasse boilers are operating in Florida; one mill and 5 bagasse boilers in Texas; and one mill and 3 bagasse boilers in Hawaii. These mill closings and consolidations were the result of economic conditions that dictated this for survival of the industry. The FSI believes that the Industrial Boiler MACT rule as proposed by EPA will have similar economic or even worse consequences.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2601
Comment Excerpt Number: 3

Commenter Name: Robert E. McKenna
Commenter Affiliation: Motor and Equipment Manufacturers Association
Document Control Number: EPA-HQ-OAR-2002-0058-2778.1
Comment Excerpt Number: 1

Comment: As context for these comments, it is important to consider that manufacturers are attempting to fully recover from the steepest economic downturn since the 1930s and bring back the 2.2 million high-wage jobs lost during recent years. MEMA strongly urges federal policy makers to create conditions that will lead to economic expansion and not stifle the industrial and manufacturing vitality necessary to create
jobs and technologies that will continue to improve the nation's air quality. Imposing unduly strict mandates on the manufacturing sector will not accomplish any of these objectives.
New and overly stringent standards for industrial boilers will have an immediate impact on our members' bottom line without demonstrated environmental benefits. Compliance costs associated with these harsh and inflexible proposed rules will cost U.S. manufacturing jobs and hurt global competitiveness, just as the economic recovery attempts to gain more traction. Further, as described below, the severity of the proposed standards may lead to the perverse effect of deterring projects that otherwise would realize environmental improvements.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-3193
Comment Excerpt Number: 1

Commenter Name: Randy A. Gerg
Commenter Affiliation: Hexion Specialty Chemicals, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2634.1
Comment Excerpt Number: 1

Comment: A single unifying theme lies at the heart of our comments on the proposed Industrial Boiler MACT standard – the proposed standards are far more stringent than needed to assure protection of health and the environment from industrial boiler HAP emissions. We are committed to operating in an environmentally responsible and sustainable manner. However, as an industry we are facing a withering economic slump and fierce competition from overseas. Therefore, it is imperative for mandatory environmental controls such as the Industrial Boiler MACT standard to be tailored as closely as possible such that health and the environment are protected without requiring unnecessary expenditures of time and resources. EPA has the legal discretion and technical justification to substantially reduce the burden of the standard while still providing ample protection to health and the environment.
EPA can provide reasonable approaches in its final Boiler MACT rule that will improve air quality and target investments strategically, preventing severe job losses and tens of billions of dollars in unnecessary regulatory costs.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2601
Comment Excerpt Number: 3

Commenter Name: Lewis F. Gossett
Commenter Affiliation: South Carolina Manufacturers Alliance
Document Control Number: EPA-HQ-OAR-2002-0058-2602.1
Comment Excerpt Number: 1

Comment: We are extremely concerned that the proposed industrial Boiler MACT standards will impede manufacturing recovery in this country and create even more severe competitive disadvantages for our companies in the global marketplace. I call to your attention the following points:

At a time when our economy is fragile and our country faces almost 10% unemployment, this proposed standard would add a significant layer of costs for industry that will close factories, mills, and businesses, and cost thousands of additional jobs.

In the forest products industry alone, these rules could cost $6-7 billion over the next two to four years when the industry only earned one billion in each of the last two years. This will result in severe hardship and tens of thousands of job losses in this sector.

This regulation will no doubt encourage US manufacturing to move off-shore and will increase reliance on imported fossil fuels.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-3193
Comment Excerpt Number: 1

Commenter Name: William R. Ermatinger
Commenter Affiliation: Northrop Grumman
Document Control Number: EPA-HQ-OAR-2002-0058-2506.1
Comment Excerpt Number: 1

Comment: At its Newport News shipyard, NGSB owns and operates five residual oil-fired industrial boilers (consisting of three -powerhouse" stationary boilers for supplying process and building steam, and two barge-mounted boilers for supplying high pressure steam to ships under construction). NGSB also operates various natural gas or distillate oil-fired boilers to produce steam or hot water process heating and comfort heating in buildings and warehouses located at the Newport News shipyard and throughout the Gulf Coast operations. NGSB has determined that these boilers will be significantly, adversely affected by these regulations, if adopted as proposed.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2418.1
Comment Excerpt Number: 4

Commenter Name: David Roosevelt
Commenter Affiliation: Cabazon Band of Mission Indians
Document Control Number: EPA-HQ-OAR-2002-0058-2676.1
Comment Excerpt Number: 2

Comment: The Colmac Energy, Inc. biomass plant on the Tribe's reservation is one of the largest (possibly the largest in terms of power delivered) biomass power plants in the United States, and the Tribe believes it is the flagship of California's 33-plant biomass power industry. The Colmac plant has operated for over 18 years, providing a secure and very important source of revenue for the Tribe, as well as approximately 150 jobs here in the rural area of the Coachella Valley where unemployment is of grave concern.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2418.1
Comment Excerpt Number: 4

Commenter Name: David A. Buff
Commenter Affiliation: Golder Associates Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2801.1
Comment Excerpt Number: 5

Comment: Jobs directly associated with the sugar industry include those employed at the sugar mills, those employed in the agricultural operations, and administrative personnel. In Florida, the total direct employment in the sugar industry is approximately 5,000 persons; in Texas, it is 1,000 persons; and in Hawaii, it is 800 persons. Indirect employment (contractors, vendors, consultants, etc.) is many times these numbers.

The worst case impact of the proposed Boiler MACT rule is the complete shutdown of the sugar industry in the U.S and the moving of it overseas. In this case, the total U.S. employment loss would be approximately 6,800 persons. A less conservative estimate would be the closing of several mills and further consolidation of the industry. Consolidation would likely cut approximately 2,000 employees in Florida and 500 in Texas from the payrolls. Due to the locations of all the mills in or very nearby small agricultural-based towns, that depend 75% to 100% on these sugar mills for their local economy, these towns, such as the "Glades" areas of South Florida, will fall into financial ruin by the closing of these mills.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2601
Comment Excerpt Number: 3

Commenter Name: W. Randall Rawson
Commenter Affiliation: American Boiler Manufacturers Association
Document Control Number: EPA-HQ-OAR-2002-0058-2698.1
Comment Excerpt Number: 7

Comment: If properly designed to reflect the broad range of boiler designs and operational conditions, as well as manufacturers' emission guarantee levels, the Boiler MACT will stimulate the creation of jobs in the boiler and boiler-related equipment industry. To the extent that EPA develops a Boiler MACT rulemaking that is achievable in practice for boiler owners and operators, the proposal will create solid, well-paid, professional, skilled and unskilled manufacturing jobs attendant to the upgrade, optimization and replacement of existing boilers around the United States. In addition, service jobs associated with the installation and maintenance of these systems, as well as service jobs associated with required tune-ups and energy assessments will be created. These jobs will be significant contributions to our local, state and national economies – contributions that must not be overlooked or minimized.

Response: EPA attempted to estimate the increase in jobs due to the proposed regulation. All catagories were not captured quantitatively.

Commenter Name: Arnold Schwarzenegger
Commenter Affiliation: Governor Arnold Schwarzenegger
Document Control Number: EPA-HQ-OAR-2002-0058-2697.1
Comment Excerpt Number: 8

Comment: In order to support biomass facilities and other renewable energy resources, California imposes a public goods charge to provide incentives and financial support to make them economically viable. More than 70 percent of California's biopower generation from solid-fuel biomass facilities in the State receives funding from this program.

Despite State subsidies, the total generating capacity from solid fuel biomass has decreased from 994 megawatts (MW) in the 1990s to 667 MW today, despite a potential to generate 3,421 MW from biomass resources. Only one new facility has been developed since 2000.

The power plants also have existing power purchase agreements and would not be able to pass the cost of the retrofit on to utility ratepayers. The Energy Commission's analysis indicates that the existing biomass power plants would not be able to fund the retrofit needed to meet the MACT Rule and would discontinue operation.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2601
Comment Excerpt Number: 3

Commenter Name: Bobby B. Howell
Commenter Affiliation: Mississippi House of Representatives
Document Control Number: EPA-HQ-OAR-2002-0058-3193
Comment Excerpt Number: 1

Comment: I urge your reconsideration of the Boiler MACT rule. We are in perilous economic times and further regulation on our industries will simply be catastrophic. Industries in America are the most regulated in the world and are finding it increasingly difficult to compete in a global market. The proposed rule is unnecessarily stringent and costly.

Response: The EPA used a standard market analysis to analyze the proposed MACT standards. The approach uses a single period multimarket partial equilibrium model to compare pre-policy market baselines with expected post-policy market outcomes. The analysis' time horizon is the intermediate run; some production factors are fixed and some are variable and is distinguished from the very short run where all factors are fixed and producers cannot adjust inputs or outputs.

The intermediate time horizon allows us to capture important transitory stakeholder outcomes. Key measures in this analysis include industry-level changes in price levels, production and consumption, jobs, international trade, and social costs (changes in producer and consumer surplus). The analysis did not show large changes in production, prices, or imports.

Commenter Name: Sean M. O'Keefe
Commenter Affiliation: Alexander and Baldwin, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-3196
Comment Excerpt Number: 1

Comment: As proposed, capital investments of up to $50 million dollars would be necessary in order for the Puunene Mill boilers to comply with the Boiler MACT standards, assuming compliance with the standards is possible at all for the existing boilers. In addition, annual facility operating costs would be expected to increase by up to $6 million. These are costs which HC&S may simply be unable to bear, threatening the continued viability of the company, along with its 800 well-paying jobs and $100 million annual contribution to the local economy, at a time when Maui, like the rest of the nation, is already struggling to cope with a prolonged economic downturn and the job losses that have come with it.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2418.1
Comment Excerpt Number: 4

Commenter Name: Robert L. Garfield
Commenter Affiliation: Food Industry Environmental Council
Document Control Number: EPA-HQ-OAR-2002-0058-2718.1
Comment Excerpt Number: 1

Comment: It is vital to consider that manufacturers, including the food industry, are attempting to fully recover from the steepest economic downturn since the 1930s and bring back the 2.2 million high-wage jobs, including those in the food retail and food service industries, lost during recent years. FIEC strongly urges federal policy makers to create conditions that will lead to economic expansion and not stifle the industrial and manufacturing vitality necessary to create jobs and technologies that will continue to improve the nation's air quality. Imposing unduly strict mandates on food processors will not accomplish any of these objectives.

New and overly stringent standards for industrial boilers will have an immediate impact on many food producers bottom line without demonstrated environmental benefits. Compliance costs associated with these harsh and inflexible proposed rules will cost U.S. manufacturing jobs and hurt global competitiveness, just as the economic recovery attempts to gain more traction. Further, as described below, the severity of the proposed standards may lead to the revaluation of projects that otherwise would realize environmental improvements.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2601
Comment Excerpt Number: 3

Commenter Name: Stan Stuart
Commenter Affiliation: Catawba Paper Mill
Document Control Number: EPA-HQ-OAR-2002-0058-3156
Comment Excerpt Number: 1

Comment: As an employee at a world class paper mill, and having recently learned about the proposed boiler MACT legislation, I`m worried about the far-reaching and actually kind of short-sighted impact this legislation will have on industry and our economy.
I do support many clean air and water initiatives (actually most). It is just this one that scares me. I think it is a `too far too fast` kind of demand put on industry at a time when we can`t afford to risk jobs and growth because of deferred expenses.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2601
Comment Excerpt Number: 3

Commenter Name: Chris Jamer
Commenter Affiliation: Oregon Forest Industries Council
Document Control Number: EPA-HQ-OAR-2002-0058-2928.1
Comment Excerpt Number: 1

Comment: OFIC appreciates that the Environmental Protection Agency (EPA) has limited ability to take the current economic situation into consideration when promulgating the MACT and associated rules. However, Oregon is suffering from unemployment numbers far above the national average, and in some cases in rural Oregon TWICE the national average. OFIC urges EPA to consider the context of the rulemaking not as a factor inand-of-itself but rather as motivation to try to find every legal and administrative way to avoid the certain, draconian impacts on the forest sector that will occur if the proposed rule is implemented as written.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2601
Comment Excerpt Number: 3

Commenter Name: Allen Sanders
Commenter Affiliation: AbitibiBowater
Document Control Number: EPA-HQ-OAR-2002-0058-3177.1
Comment Excerpt Number: 1

Comment: Our Company is working aggressively to emerge from creditor protection. At the same time, this regulation represents an additional capital cost for each individual facility – tens of millions of dollars in most cases. Based on a preliminary assessment, the Company estimates it will cost close to $200 million for all six of its US paper mills to meet new compliance standards, and we are not sure it can be done consistently with current technology. This dilemma puts several of our facilities and our jobs at risk. We are aware that in the U.S., this rule will cost the forest products industry almost $7 billion over the next two to four years – an amount that is not sustainable in today's economy.
Over the past ten years, our Company has permanently closed six pulp, paper and wood products facilities in the U.S. and indefinitely idled one due to high operating costs that prohibited them from successfully competing in the marketplace, and put thousands of our fellow employees out of a job.
The proposed rule is unnecessarily stringent and costly.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2418.1
Comment Excerpt Number: 4

Commenter Name: Jay Backus
Commenter Affiliation: Augusta Newsprint Company
Document Control Number: EPA-HQ-OAR-2002-0058-3153.1
Comment Excerpt Number: 1

Comment: We believe the proposed Industrial Boiler MACT standards are far more stringent than needed to assure protection of health and the environment from industrial boiler emissions of hazardous air pollutants (I-IAPs). As AbitibiBowater emerges from Chapter 11 bankruptcy protection in the second half of 2010, we face a withering global economic slump and fierce competition from overseas manufacturers. Over the past ten years, AbitibiBowater has indefinitely idled one and closed six facilities in the U.S. due to high operating costs. In 2008, Augusta Newsprint was forced to take eleven days curtailment of operations due to the lack of newsprint orders. In 2009, thirty-nine days of curtailment were imposed on the Augusta mill, reflecting the continuing decline in the newsprint market. Therefore, it is imperative that the Industrial Boiler MACT standard be tailored to protect health and the environment without requiring unnecessary expenditures of time and resources.

Estimates show that $12-14 million in initial capital would be required for Augusta Newsprint Company to begin to make the necessary alterations to meet these stringent proposed limits, not including additional annual operating and labor costs associated with maintaining regulatory equipment, compliance tests, etc. With no return on investment and no economic gain, and at a time when we are already struggling to maintain profitability and to be a viable competitor in a declining newsprint market, the sustainability of Augusta Newsprint would be in jeopardy.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2418.1
Comment Excerpt Number: 4

Commenter Name: Richard Caserta
Commenter Affiliation: Red Hill Grinding Wheel Corp
Document Control Number: EPA-HQ-OAR-2002-0058-2996
Comment Excerpt Number: 1

Comment: It is important to consider that manufacturers are attempting to fully recover from the steepest economic downturn since the 1930s and bring back the 2.2 million high-wage jobs lost during recent years. Red Hill Grinding Wheel Corp. strongly urges federal policy makers to create conditions that will lead to economic expansion and not stifle the industrial and manufacturing vitality necessary to create jobs and technologies that will continue to improve the nation’s air quality. Imposing unduly strict mandates on the manufacturing sector will not accomplish any of these objectives. These mandates hit small companies such as ours hard directly and indirectly. REMEMBER IT IS SMALL COMPANIES IN THIS COUNTRY THAT PROVIDE MOST OF THE JOBS.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-3193
Comment Excerpt Number: 1

Commenter Name: Cindy Domenico
Commenter Affiliation: Boulder County Commissioners
Document Control Number: EPA-HQ-OAR-2002-0058-2704.1
Comment Excerpt Number: 1

Comment: In 2010 Boulder County received grant funding from the US Forest Service, The Department of Energy and the Colorado Department of Local Affairs as well as Qualified Energy Conservation Bonds to install another 3.3MMBtu biomass boiler at the 150,296 square foot Boulder County Jail.
Boulder County supports the new HAP emission standards with the exception of the Particulate Matter (PM) limit of .03 lbs/BTU limit, based on Maximum Achievable Control Technology (MACT) for all new boilers, regardless of size. The cost to add the equipment to meet the PM

Standards on the boiler at the Boulder County Jail will be $110,000, which is more than a third of the cost for the biomass boiler by itself. This is a significant impact to the project cost and makes the small biomass boiler option financially challenging.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2418.1
Comment Excerpt Number: 4

Commenter Name: William L. Kovacs
Commenter Affiliation: United States Chamber of Commerce
Document Control Number: EPA-HQ-OAR-2002-0058-2799.1
Comment Excerpt Number: 1

Comment: Clean Air Act (CAA) section 112(d) requires EPA to set emissions standards for new and existing sources of HAPs that achieves the maximum degree of reduction while taking into account the costs of achieving such reductions, any non-air quality health and environmental impacts, and energy requirements. The Boiler MACT standards proposed in this rule are significantly more stringent, and more expensive, than the earlier version of this Boiler MACT rule proposed by EPA in 2004. EPA estimates the new Boiler MACT will cost the regulated community—which consists of roughly 13,600 units—$9.5 billion in capital expenditures, $3.2 billion per year in total annual costs, and $2.9 billion in social costs.

When stacked on top of the various other costly regulations already in force or soon to be added by EPA and other agencies, the true cost of the Boiler MACT could be significant. For domestic manufacturers, the cost disparity between doing business in America and doing business “somewhere else” is growing rapidly. Boiler MACT is an expensive rule on its own; when combined with greenhouse gas permits, five to six new National Ambient Air Quality Standards, Clean Water Act expansion, chemical action plans, and the litany of other new major environmental regulations on EPA’s drawing board, the added costs for businesses can be extreme. The Chamber recognizes the role of federal regulation in seeking to assure public health and safety, protecting the environment, providing needed guidance about federal tax rights and obligations, and establishing fair and uniform rules of interstate commerce. Overregulation, particularly in the environmental arena, is a growing problem for a free enterprise system that could and should be focused on creating jobs and lifting the nation out of economic purgatory.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-3193
Comment Excerpt Number: 1

Commenter Name: David Bonistall

Commenter Affiliation: NewPage Corp
Document Control Number: EPA-HQ-OAR-2002-0058-2920.1
Comment Excerpt Number: 1

Comment: The proposed Boiler Maximum Achievable Control Technology (MACT) rule has the potential to be very costly for NewPage. We have conducted a limited site-specific engineering review to determine the Boiler MACT compliance costs for our U.S. facilities. These preliminary engineering estimates indicate extraordinary capital expenditures and several million dollars in additional annual operating costs. These costs are significant and will put NewPage at a distinct disadvantage as we compete in a global marketplace with other paper producers located in jurisdictions that do not have to comply with these requirements. In order to remain cost competitive with foreign competition, we cannot pass-on these substantial compliance costs.

NewPage is concerned that without significant changes to the proposed Boiler MACT rule, U.S. manufacturing will need to spend billions of dollars to fund compliance requirements at a time of significant economic pressure with a struggling economy. As a result, additional manufacturing facilities will be closed and jobs will be shed. We are very concerned that mill closures may have to be the final fate for some of our facilities unless changes to the proposed rule are made to significantly lessen the financial burden for compliance.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2418.1
Comment Excerpt Number: 4

Commenter Name: Bill Thomas
Commenter Affiliation: Shuqualak Lumber Company, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2742.1
Comment Excerpt Number: 1

Comment: As an industry, forest products manufacturers are experiencing a severe economic downturn and fierce competition from overseas producers, an environment that we do not think will change anytime soon. We at Shuqualak Lumber have studied the proposed Boiler MACT and listened to our industry leaders, and we are quite concerned about the impact of this rule on our already-diminished operations.

If this rule is finalized in its current form, we believe operations like ours may simply disappear.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2601
Comment Excerpt Number: 3

Commenter Name: John C. deRuyter
Commenter Affiliation: DuPont
Document Control Number: EPA-HQ-OAR-2002-0058-2793.1
Comment Excerpt Number: 1

Comment: It is obvious to us that the combination of the three proposed combustion rules in concert with the solid waste definition proposed rule constitute the largest rulemaking package from an applicability and impact perspective in EPA's history, with this Boiler/Process Heater MACT (Boiler MACT) rule having the greatest potential impact. The number of facilities and combustion units potentially subject to these rules is staggering. The data and analysis aggregated and developed by EPA is voluminous. The potential capital cost for this rule is estimated by EPA to be $9.5 billion, and industrial estimates are significantly higher. The collateral impacts of such a high cost and the continuing O&M costs will be significant to the affected sources, employment, and the U.S. economy in general when considered against the backdrop of the current economic troubles.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-3193
Comment Excerpt Number: 1

Commenter Name: John Ledger
Commenter Affiliation: Association Oregon Industries
Document Control Number: EPA-HQ-OAR-2002-0058-2925.1
Comment Excerpt Number: 1

Comment: New and overly stringent standards for industrial boilers will have an immediate impact on Oregon's economy without demonstrated environmental benefits.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2601
Comment Excerpt Number: 3

Commenter Name: Thomas D. Evans
Commenter Affiliation: Coastal Resources Company
Document Control Number: EPA-HQ-OAR-2002-0058-2865.1
Comment Excerpt Number: 1

Comment: The proposed Boiler MACT rule would hit Coastal very hard economically. Coastal's cost to comply might approach $40 million of capital costs, which would be a ton • h pill to swallow for a company that is in a super-competitive, low-margin industry and whose annual sales is only $200 million. And incremental annual operating & maintenance costs could range from several hundred thousand to $2 million per year. Fortunately, Coastal is one of the best performers in the industry, and, hopefully, would figure out a way to stay in business. However, I can assure you that many companies in our industry, most of whom have lost millions over the past 3 or 4 years, would choose to stop the bleeding and simply shut down.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2418.1
Comment Excerpt Number: 4

Commenter Name: Clark Diehl
Commenter Affiliation: Chips, Inc and ArborTech Forest Products
Document Control Number: EPA-HQ-OAR-2002-0058-2468
Comment Excerpt Number: 1

Comment: I am a co-owner of two lumber mills in Virginia. Chips, Inc. employs 70 people and ArborTech Forest Products employs 80. Chips, Inc. is classified as a synthethic minor source and ArborTech is Title 5. Both mills are in rural settings. The new proposed Boiler MACT rules would cost Chips, Inc. over $600,00 and ArborTech over $1,500,00 to comply with the new rule limits (if that is even possible). The lumber industry is in the third year of a severe downturn. Almost 50% of 2006 production has gone away along with the jobs. If these new proposed rules go into effect, our companies may be forced to close if these amounts of capital can't be borrowed. These new rules put 150 direct jobs, and over 400 indirect jobs (loggers, truckers,etc.) at risk.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2418.1
Comment Excerpt Number: 4

Commenter Name: Jacquelyn Taylor
Commenter Affiliation: South Carolina Pulp and Paper Association
Document Control Number: EPA-HQ-OAR-2002-0058-3154.1
Comment Excerpt Number: 1

Comment: One of SCPPA's main concern with the proposed Industrial Boiler MACT is the proposed standards are far more stringent than needed to assure protection of health and the environment from industrial boiler HAP emissions and do not strike a balance with economic health of the effected sources. SCPPA and its members are committed to operating in an environmentally responsible and sustainable manner. However, South Carolina industry faces a contemptuous global economic slump and stern competition from overseas manufacturers. It is therefore imperative for mandatory environmental controls such as the Industrial Boiler MACT standard to be tailored as closely as possible such that health and the environment are protected without requiring unnecessary expenditures of time and resources.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2601
Comment Excerpt Number: 3

Commenter Name: Thomas Bakk
Commenter Affiliation: State of Minnesota Senate
Document Control Number: EPA-HQ-OAR-2002-0058-2950
Comment Excerpt Number: 1

Comment: Forest products is one of the leading industrial sectors in Minnesota, generating over $8.6 billion in revenue and providing more than 36,000 jobs. The American Forest and Paper Association (AF&PA) estimates that the proposed Boiler MACT rule will cost the forest products industry in Minnesota more than $160 million at a time when these companies are working hard to emerge from the deepest recession in our nation since the Great Depression. The estimated cost for all affected boilers in Minnesota is $730 million, including other industrial sectors as well as commercial and government facilities.

We believe that the EPA proposed Boiler MACT rule will severely impact the forest products industry as well as other Minnesota industries and commercial and public facilities. The proposed rule is more restrictive than needed to protect public health and the environment with emission limits so stringent that they are, in some cases, not detectable or achievable. The cost to individual mills could be tens of millions of dollars at a time of fierce international competition and a weak economy.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2601
Comment Excerpt Number: 3

Commenter Name: Llewellyn Matthews
Commenter Affiliation: Northwest Pulp and Paper Association
Document Control Number: EPA-HQ-OAR-2002-0058-2693.1
Comment Excerpt Number: 1

Comment: NWPPA represents pulp and paper mills in the states of Oregon, Washington and Idaho. Within these three states, the forest products industry is home to at least 55 boilers affected by the proposed rules and many of the largest of these boilers are locate d at pulp and paper mills. The cost of emission reduction technology (controls) under the proposed rule for affected forest products industry boilers in these states is estimated at $350,000, 000. As such, NWPPA believes the financial impact of the rules as proposed will put half of our pulp and paper mills at risk of closure and will also put approximately half of the jobs at our mills at risk.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2601
Comment Excerpt Number: 3

Commenter Name: Wilson Jones, Jr
Commenter Affiliation: J.W. Jones Lumber Company
Document Control Number: EPA-HQ-OAR-2002-0058-3139
Comment Excerpt Number: 2

Comment: To even try to meet the limits would require expenditures much higher than our business could begin to afford; we will have to close our business.

The impact of this legislation would force the closure of our two mills and the loss of one hundred fifty jobs not including the impact on others in our area. Our two mills combined economic contributions to the economy include payroll of $6 million annually, payments to loggers and land owners for the purchase of logs of $16 million annually, purchases of supplies of $1 million and payments for outside contracted services of $1.7 million each year. In addition we pay local property taxes of $160 thousand each year. Many other mills have greater financial impact.

If the rules are implemented as proposed the forest products industry in our nation will not survive. Much of the forest products industry is comprised of family owned companies that have struggled to just stay open in the economic recession and the depression in the home building and real estate sectors of our nation’s economy. The proposed Boiler MACT Rules will nail the coffin on our industry with significant impact now and in future years on the cost of everything that uses wood and wood by-products.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2418.1
Comment Excerpt Number: 4

Commenter Name: Deb Hawkinson

Commenter Affiliation: Hardwood Federation
Document Control Number: EPA-HQ-OAR-2002-0058-2781.1
Comment Excerpt Number: 2

Comment: Hardwood facilities cannot afford unnecessary additional regulatory costs particularly given the current economic climate. In fact, many have already closed and more are facing bankruptcy. Most U.S. hardwood businesses are family-owned; many are multi-generational, and most have sales between $1 and $20 million per year. The current severe recession has had a devastating impact on the hardwood and related industries. Production workers were especially hard hit; just between 2006 and 2008, more than 42,000 jobs were lost, and more than half of production jobs disappeared between 2000 and 2008. The housing crisis has meant more job loss of tens of thousands of employees and many hardwood companies have gone bankrupt.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2601
Comment Excerpt Number: 3

Commenter Name: Albert A. Carter
Commenter Affiliation: Board of Commissioners, Grays Harbor County
Document Control Number: EPA-HQ-OAR-2002-0058-3191
Comment Excerpt Number: 2

Comment: We are concerned over EPA's proposed Boiler MACT rule and the implications that will burden, limit, or close operations at existing boiler and cogeneration facilities throughout the nation.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-3193
Comment Excerpt Number: 1

Commenter Name: Richard Lovely
Commenter Affiliation: Grays Harbor PUD
Document Control Number: EPA-HQ-OAR-2002-0058-2770.1
Comment Excerpt Number: 2

Comment: We believe the rule would have a significant economic impact on the industries in our area that would face expensive investments for compliance at a time with those investments simply cannot be funded. In our case, cost prohibitive requirements could result in the shutdown of the biomass generation facility, which would leave our public utility district forced to quickly try to find another renewable resource investment at likely a higher cost to ratepayers.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2601
Comment Excerpt Number: 3

Commenter Name: Kristine M. Krause
Commenter Affiliation: Wisconsin Electric Power Company, We Energies
Document Control Number: EPA-HQ-OAR-2002-0058-2679.1
Comment Excerpt Number: 2

Comment: Woody biomass is a renewable fuel readily available in Wisconsin. It is a fuel that can be sustainably harvested. The 50 mw biomass unit we are currently developing is projected to create 150 new jobs just in the process of harvesting fuel.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2601
Comment Excerpt Number: 3

Commenter Name: Bill Thomas
Commenter Affiliation: Shuqualak Lumber Company, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2742.1
Comment Excerpt Number: 2

Comment: One alternative to huge investments in control is to deliberately reduce our allowable production capacity to a level that would make our mill a non-major HAP source, however, this option of reducing production makes our mill non-competitive. We would then be subject only to the area source rules which may also prove to be very expensive for our company. Other alternatives are not any more palatable, but would include major changes in the processes for the sake of eliminating boilers at our site altogether. Again, we are talking about extremely expensive propositions in a down economy.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2418.1
Comment Excerpt Number: 4

Commenter Name: Dustin Madlung
Commenter Affiliation: Citizen
Document Control Number: EPA-HQ-OAR-2002-0058-3160
Comment Excerpt Number: 3

Comment: The predicted initial costs are astronomical to meet the proposed emission standards, and the millions of dollars it will cost to keep the pollutant controls running will hit industries hard and there is debate whether or not the emission standards can even be met at all. There will be plant closings and job losses that affect communities all over America. With the current economy and jobless rate, this does not bode well, and let's not forgot all the related jobs just to the pulp and paper industry such as logging and trucking. In an ever increasing globalization world, one must not be giving advantages to foreign competitors, many that do not even have to come close to meeting many emission standards that we meet today, so this law will just allow for more pollution to happen elsewhere as outsourced plants go elsewhere and not meet the currents standards that they are meeting in the USA.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-3193
Comment Excerpt Number: 1

Commenter Name: S. Lewis Ebert
Commenter Affiliation: North Carolina Chamber
Document Control Number: EPA-HQ-OAR-2002-0058-2890.1
Comment Excerpt Number: 3

Comment: These regulations will tremendously impact North Carolina's economy as our state has the highest volume of boilers in the country. Manufacturers are the backbone of our state's economy and we are concerned that the potential impact of the regulations could be unsustainable for North Carolina's manufacturers. Both small and large businesses are vulnerable to the costly regulatory burdens under the rule, as are municipalities, universities, government facilities, and commercial entities. It is estimated that the rule will cost North Carolina's industry alone $1.46 billion for compliance and tens of billions in capital costs for manufacturers across the country.
This is not the time to impose these sorts of costs on North Carolina businesses, when our state has already lost over 250,000 jobs during this recession. It will be counterproductive to economic recovery efforts to impose a standard that will hurt our nation's local economies which are already struggling to emerge from the recession.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2601
Comment Excerpt Number: 3

Commenter Name: Williams Wicks
Commenter Affiliation: Packaging Corp
Document Control Number: EPA-HQ-OAR-2002-0058-3130
Comment Excerpt Number: 3

Comment: Administrator Jackson, the establishment of the Boiler MACT standard will be a signed death warrant for the industry I work in and doubtlessly for American business as well, costing $US billions. This burdensome cost will have to come at the expense of growth and will create a climate of business uncertainty. Boiler MACT will place the United States pulp and paper industry at a severe competitive disadvantage worldwide. Brazil, Russia, India, and China are certainly not going to going to institute this standard.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-3193
Comment Excerpt Number: 1

Commenter Name: Kellie Daniels
Commenter Affiliation: Grays Harbor Chamber of Commerce
Document Control Number: EPA-HQ-OAR-2002-0058-2815.1
Comment Excerpt Number: 3

Comment: Times are hard for the timber industry, as hard as they've ever been. Using other power sources will put pressure on Sierra Pacific to cut back production, meaning jobs will be lost for loggers, truckers and millwrights. More indirect jobs will be lost as a result, and the company won't be utilizing an existing and readily available renewable energy source.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2601
Comment Excerpt Number: 3

Commenter Name: Patti Gettinger
Commenter Affiliation: Graphic Packaging International Inc
Document Control Number: EPA-HQ-OAR-2002-0058-3197
Comment Excerpt Number: 4

Comment: The costs to individual manufacturing facilities could be tens of millions of dollars in additional capital expenditures. Total capital costs for the forest products industry alone are

estimated at about $7 billion and the costs to all manufacturing operations could range from $20 to $50 billion.
The paper industry is already struggling financially: many large producers have had to shutter or idle plants, permanently lay off thousands of workers, or even declare bankruptcy. Implementing the proposal as published would be devastating financially to many of our citizens, businesses and communities at a time when US unemployment already approaches 10% and our economy risks a double-dip recession — yet provides little, if any, additional public health protection.
As an employee of Graphic Packaging International, Inc. (GPI), the largest US producer of paperboard used in folding carton applications, I am concerned about how these regulations could negatively affect me personally — my job, income, family, retirement, health benefits, etc.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2418.1
Comment Excerpt Number: 4

Commenter Name: Carolyn Van Asten
Commenter Affiliation: Packaging Corp. of America
Document Control Number: EPA-HQ-OAR-2002-0058-3159
Comment Excerpt Number: 4

Comment: The impacts this proposed legislation will have on industry is guaranteed to affect the everyday lives of American citizens. Energy costs and costs of goods and materials will rise to cover the installation and operation of necessary control devices. Some companies may send work to overseas locations where more reasonable standards are set. It is even likely that some locations will need to shut down all together, as they will not be able to afford the necessary capital investment. The EPA estimates initial capital costs of $10.0 billion to comply, along with an added annual operating cost of $3,2 billion. The EPA further estimates the social costs of the proposed rule to be $2.9 billion and between 6,000 and 12,000 American jobs. These economic and social costs estimates may be overly conservative. The American Forest and Paper Association estimates the capital investment for all industries could range between $20 and $50 billion and between 70,000 and 181,000 jobs could directly be affected. Ultimately, this bill will unreasonably limit emissions from boilers with a significant cost to American pocketbooks and American jobs.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-3193
Comment Excerpt Number: 1

Commenter Name: Kari Frantom
Commenter Affiliation: Graphic Packaging

Document Control Number: EPA-HQ-OAR-2002-0058-3142
Comment Excerpt Number: 4

Comment: The costs to individual manufacturing facilities could be tens of millions in additional capital expenditures. I have heard that total capital costs for the forest products industry alone are estimated at about $7 billion and the costs to all manufacturing operations could range from $20 to $50 billion. [Footnote: Cost, job loss and other data provided by the American Forest and Paper Association] As EPA turns to developing a final Boiler MACT rule, I hope you will carefully consider sustainable approaches that protect the environment and public health while fostering economic recovery and jobs.

Response:
See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2601
Comment Excerpt Number: 3

Commenter Name: Kellie Daniels
Commenter Affiliation: Grays Harbor Chamber of Commerce
Document Control Number: EPA-HQ-OAR-2002-0058-2815.1
Comment Excerpt Number: 5

Comment: Another anchor business for Grays Harbor County relies on biomass cogeneration: Grays Harbor Paper. They are considered to be one of the greenest businesses in the state, getting most of their energy from burning hogfuel. This rule may not affect them at the moment, but it seems certain to expand to include boilers of their capacity in the future. This would further threaten employment in our county.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2418.1
Comment Excerpt Number: 4

Commenter Name: Deb Hawkinson
Commenter Affiliation: Hardwood Federation
Document Control Number: EPA-HQ-OAR-2002-0058-2781.1
Comment Excerpt Number: 5

Comment: At a time when Congress and the Administration are hard at work to create rural jobs, promote green energy, and strengthen small business this rule would raise costs and encourage a move away from the use of renewable waste to power kilns.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-3193
Comment Excerpt Number: 1

Commenter Name: Patrick Strauch
Commenter Affiliation: Maine Forest Products Council
Document Control Number: EPA-HQ-OAR-2002-0058-3120.1
Comment Excerpt Number: 8

Comment: We believe that this rule will have a negative effect on new biomass boiler investment in the future. The proposed emission requirements are for biomass boilers of any size, and will require costly pollution controls- often exceeding $100,000 for installation for smaller boilers, and tens of thousands of dollars each year in maintenance and operational expenses.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2601
Comment Excerpt Number: 3

Commenter Name: John Hopewell
Commenter Affiliation: American Coatings Association
Document Control Number: EPA-HQ-OAR-2002-0058-2886.1
Comment Excerpt Number: 8

Comment: Boiler MACT and other upcoming air regulations will negatively impact paint and coatings industry jobs.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2601
Comment Excerpt Number: 3

Commenter Name: Mac Gibson
Commenter Affiliation: Alabama Timber Industries, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2717.1
Comment Excerpt Number: 8

Comment: We must state that our company would be unable to afford the cost of installing the level of controls required to comply with the proposed emission limits. We would be forced to close our facility which currently employs 22 people and provides thousands of dollars in tax revenue to the surrounding community.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2418.1
Comment Excerpt Number: 4

Commenter Name: Marvis A. Lewallen
Commenter Affiliation: Clearwater Paper
Document Control Number: EPA-HQ-OAR-2002-0058-2862
Comment Excerpt Number: 10

Comment: Our industry sector has been savaged by the economy and the volatility of fossil fuel prices. It is simply not an option to convert to exclusively natural gas as a fuel so as to maintain a bearable level of regulation. Biomass is a low-HAP fuel and should not be unduly penalized through the NESHAP process. Doing so will result in plant closures, unemployment and further flight of manufacturing operations overseas where the level of regulation is substantially lower. EPA must recognize that the impact of its rules will be increased HAP emissions through additional uncontrolled combustion of biomass and decreased domestic employment. Congress never intended such draconian effects from the NESHAP program.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2601
Comment Excerpt Number: 3

Commenter Name: Holly R. Hart
Commenter Affiliation: United Steelworkers Union
Document Control Number: EPA-HQ-OAR-2002-0058-2964.1
Comment Excerpt Number: 17

Comment: EPA's own figures from the rule proposal show capital costs to achieve compliance of $9.4 billion and ongoing annual costs of $3.1 billion. This does not include figures for the natural gas and metal process units EPA proposes to subject to a work practice standard. Industry cost estimates are upwards of twice the figures given by EPA. On a per unit basis, EPA's figures show capital costs per boiler to be up to $7.8 million with annual costs per boiler of up to $2.8 million. Many larger facilities have multiple boilers.

In the current recessionary economy, a recessionary situation that does not at present have any clear ending date, cost impacts such as those detailed above, even if EPA's calculations are more correct than the far higher industry estimates, will be sufficient to imperil the operating status of many industrial plants. Hundreds of thousands of workers in the most heavily-impacted industries, among them pulp & paper, steel, and rubber, are represented by USW. Tens of thousands of these jobs will be imperiled. In addition, many more tens of thousands of jobs in the supply chains and in the communities where these plants are located also will be at risk.

Section 112 (d) (2) of CAA requires EPA to take into account the cost of the the standards it sets as it formulates its regulatory approach. In the case of natural gas boilers it clearly has done so. USW strongly urges EPA to look seriously at the significant cost impacts of this proposed rule and reformulate its regulatory approach for the remaining subcategories in a way that substantially reduces this potentially untenable cost impact and ensures the viability of these industries and the millions of jobs and the communities dependent upon them in the current difficult economic situation.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-3193
Comment Excerpt Number: 1

Commenter Name: David Bonistall
Commenter Affiliation: NewPage Corp
Document Control Number: EPA-HQ-OAR-2002-0058-2920.1
Comment Excerpt Number: 37

Comment: We are concerned with EPA pushing industrial sources to fuel switch to natural gas through regulatory action such as the proposed Boiler MACT rule. Increases in natural gas demand will dramatically increase its cost, making U.S. based manufacturing uncompetitive. Coal is a cheaper and abundant energy source and clean coal or green coal technologies continue to develop. We recommend EPA also use the flexibility under the Clean Air Act to include incentives in the Boiler MACT Rule for industry to transition to cleaner coal technology.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-3193
Comment Excerpt Number: 1

Commenter Name: Scott Manley
Commenter Affiliation: Wisconsin Manufacturers and Commerce
Document Control Number: EPA-HQ-OAR-2002-0058-2933.1
Comment Excerpt Number: 1

Comment: WMC strongly urges federal policy makers to create conditions that will lead to economic expansion and not stifle the industrial and manufacturing vitality necessary to create jobs and technologies that will continue to improve the nation's air quality. Imposing unduly strict mandates on the manufacturing sector will not accomplish any of these objectives.
New and overly stringent standards for industrial boilers will have an immediate and adverse impact on the ability of Wisconsin manufacturers to compete in an international marketplace, and will do so without demonstrated environmental
benefits. Compliance costs associated with these harsh and inflexible proposed rules will be considerable. For example, the compliance cost in Wisconsin is expected to be $680 million, including a $470 million direct hit to Wisconsin's pulp and paper industry alone. We are very concerned that these costs will result in manufacturing job loss at a time when Wisconsin is struggling to regain its economic footing.

Response: EPA acknowledges the comments. The costs of the rule have been decreased through changes to subcategories, emission limits (based on new data, data corrections, and the MACT floor methodology discussed in the preamble to the final rule).

Commenter Name: Tim Hagley
Commenter Affiliation: Minnesota Power
Document Control Number: EPA-HQ-OAR-2002-0058-2829.1
Comment Excerpt Number: 1

Comment: MP submits these comments on EPA's proposed IB MACT giving consideration to the design and operation of our Rapids Energy Center (REC). MP is also a member of the Edison Electric Institute (EEI), the Utility Air Regulatory Group (UARG), and the Minnesota Chamber of Commerce (MCC). We have reviewed and support the written comments submitted by these organizations to this Docket.

MP's northern location and high percentage of industrial customers who operate around-the-clock make MP a winter-peaking utility. Thirteen large power customers (requiring at least 10 megawatts of generating capacity) purchase about half the electricity MP sells. Considering MPs high percentage of industrial customers who are high energy users and struggling to compete in a competitive global market economy, we are concerned that any further restrictions applicable to our facilities be implemented with reasonable timeframes and cost to minimize adverse impacts on our customers.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2418.1
Comment Excerpt Number: 4

Commenter Name: Jeffery S. Hannapel
Commenter Affiliation: National Association for Surface Finishing
Document Control Number: EPA-HQ-OAR-2002-0058-2758.1
Comment Excerpt Number: 1

Comment: The surface finishing industry is subject to very high costs for environmental, health and safety compliance. Roughly 7.5 percent of total payroll is spent on regulatory-related employees, and these employees cost on average over 20 percent more than other personnel. Plating operations spend nearly 28 percent of their total capital expenditures on pollution prevention and regulatory controls. Further, total compliance operating costs for an average job shop is approximately 6.5 percent of sales, or nearly $200,000 for a company with a sales volume of $3 million.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2601
Comment Excerpt Number: 3

Commenter Name: John T. Heard
Commenter Affiliation: The Virginia Coal Association
Document Control Number: EPA-HQ-OAR-2002-0058-2953.1
Comment Excerpt Number: 1

Comment: The recent world-wide recession and continuing economic difficulties have created extremely tough circumstances for the coal industry, manufacturers and other businesses in Virginia and the rest of the United States. These entities will be severely impacted by the proposed Industrial Boiler MACT rule standards and Area Source rule standards. As proposed, these standards are much more stringent than is necessary to assure protection of health and the environment from industrial boiler HAP emissions. The potential economic impact of these proposed regulations is also unacceptably severe. There are 92 boilers in Virginia alone that will be impacted by the proposed Boiler MACT regulations. Many of these belong to utilities or other entities that burn coal. The estimated cost of complying with the proposed Boiler MACT regulations in Virginia alone is $930,000,000. Nationwide the cost of complying with the proposed Boiler MACT regulations is estimated to be in excess of $18 billion. Consequently, the proposed Industrial Boiler MACT standards and Area Source rule standards must be extensively revised so that they are tailored to achieve health and environmental protection without requiring unnecessary expenditures of time and resources.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2601
Comment Excerpt Number: 3

Commenter Name: Paul Lyskava
Commenter Affiliation: Pennsylvania Forest Products Association
Document Control Number: EPA-HQ-OAR-2002-0058-2906.1
Comment Excerpt Number: 1

Comment: The proposed regulations are far more stringent than what is needed to assure the protection of public health and the environment from industrial boiler emissions. It will impose significant and unnecessary costs on our industry at a time when forest product companies are struggling to survive the domestic and global economic recession, tight credit markets and increased competition from overseas manufacturers. The American Forest and Paper Association has conservatively estimated that Pennsylvania wood and paper facilities will have to spend $140 million for the initial capital upgrades needed to comply with the proposed regulations, and tens of millions more annually in increased operating costs. These proposed regulations divert scarce financial resources from business recovery and the rehiring of workers.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2601
Comment Excerpt Number: 3

Commenter Name: Gary Chandler
Commenter Affiliation: Association of Washington Business
Document Control Number: EPA-HQ-OAR-2002-0058-2914.1
Comment Excerpt Number: 1

Comment: Companies located outside of the United States will not have to comply with the proposed regulations, US companies will be at an even greater competitive disadvantage than they already are.

Response:
See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-3193
Comment Excerpt Number: 1

Commenter Name: Bruce Coffee
Commenter Affiliation: Hurst Boiler and Welding Co
Document Control Number: EPA-HQ-OAR-2002-0058-2705.1
Comment Excerpt Number: 1

Comment: Our business will be directly and deleteriously affected by the proposed action. This is certain.
We build all types of boilers but the bulk of our work is targeted toward the solid fuel market. This includes coal and biomass units. We believe this will be the end for coal fired equipment altogether. Already difficult, companies will soon find it impossible to decide to improve their competitiveness by investing in a fuel-saving biomass boiler, as the increased capital expenditure will essentially kill many of the projects we have proposed. We are not sure but we could certainly predict that our workforce would be "down-sized"
Without the ability to incorporate this cost-saving fuel alternative, many of these companies will be hastened toward their demise in the hostile business environment we see today. It will be difficult to assess the number of businesses that will not be started, the number that will cease to exist and the number that will move off-shore as a result of this stifling action. At the very time when our country needs all of the breaks it can get to increase employment this action will cause many jobs to just never materialize, others to be lost and speed the day when China's economy overtakes our own. This is certain.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2601
Comment Excerpt Number: 3

Commenter Name: Catherine W. McCuthen
Commenter Affiliation: Blue Heron Paper Company
Document Control Number: EPA-HQ-OAR-2002-0058-2892.1
Comment Excerpt Number: 1

Comment: Since 2006, the paper industry, including Blue Heron, has experienced a decline due to market conditions. In 2009, Blue Heron experienced financial difficulties due to the general downturn in the economy and depressed paper prices. These financial difficulties resulted in operational curtailments and slow-downs at times throughout 2009. This financial climate has affected our company's and the industry's ability to invest in bigger capital projects for now. We are a significant employer in our community in a state where the unemployment rate is well above the national average.

The rule, as proposed, has the realistic potential of creating further economic hardship on our continued operations. Switching exclusively to natural gas is cost prohibitive. As you consider revisions to the proposed rule we hope that you consider the direct impact of the requirements on our employees and community and recognize that the result of your rule language could be to cause more layoffs in an already stressed state.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2418.1
Comment Excerpt Number: 4

Commenter Name: Joe Muehlbach
Commenter Affiliation: Quad/Graphics
Document Control Number: EPA-HQ-OAR-2002-0058-2898.1
Comment Excerpt Number: 1

Comment: The proposed Boiler MACT rule will pose economic hardships to Wisconsin's core manufacturing industries, especially forest products. The Wisconsin Paper Council has estimated that the total costs for Wisconsin manufacturing could top $680 million with the forest products industry bearing $470 million of that total. That hits a company such as Quad/Graphics twice as we will bear the costs of compliance at our facilities as well as those of one of our major suppliers — the paper mills.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2601
Comment Excerpt Number: 3

Commenter Name: Wayne J. Galler and Deborah A. Phillips
Commenter Affiliation: Georgia Industry Environmental Coalition, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2882.1
Comment Excerpt Number: 1

Comment: GIEC members form a diverse group of industries, representing an employee-base well over 55,000 and 19 major SIC codes, with the shared belief that environmental regulations should, and can be both protective and cost efficient. GIEC member companies include manufacturers of chemicals, pharmaceuticals, textiles, metals, paper products, and other materials; aerospace; utilities; railroads; and food processors.
GIEC believes that the Boiler MACT Rules, as proposed by EPA, will create an unnecessary financial burden on its member companies due to the stringency`of several of the specific standards.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2601
Comment Excerpt Number: 3

Commenter Name: Susan Swanson
Commenter Affiliation: Allegheny Hardwood Utilization Group, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2851.1

Comment Excerpt Number: 1

Comment: AHUG is an organization of hardwood industry members from the northwest and north central portion of Pennsylvania. The region is extremely rural and is dependant on resource-based industries.
The proposed rule as published by the EPA on June 4, 2010 would have a severe impact on the forest product manufacturers that are members of AHUG. It is far more restrictive than is necessary to protect the environment and could in this current economic climate have an extremely devastating impact on many industries.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2601
Comment Excerpt Number: 3

Commenter Name: Linda Barnfather
Commenter Affiliation: Washington House of Representatives
Document Control Number: EPA-HQ-OAR-2002-0058-2852.1
Comment Excerpt Number: 1

Comment: We have strong concerns about the proposed emissions limits for biomass-powered boilers and incinerators, as no current boiler could meet these proposed standards. Such regulations would harm our vital forest products industry and hurt the prospects for expanding our nation's green energy production and the jobs it brings.
While we strongly support the goals of achieving strong protections for public health and high environmental performance, we are concerned that there will be unintended consequences with the current draft proposal. Without careful reconsideration these regulations may unnecessarily harm Washington's critical forest products industry -- and that of other states in the union -- and our burgeoning efforts to utilize waste wood from the state's forest lands for renewable energy production.
The forest products industry is critical to all areas of Washington State, representing 11% of all manufacturing jobs and playing a particularly important role in rural, timber-dependent communities.
The sector provided over 45,000 jobs in 2005, generated approximately $16 billion in gross business revenue, and paid out over $2 billion in wages and over $100 million in tax receipts. [Footnote: http://www.ruraltech.org/projects/wrl/sfr/pdf/RetentionReport.pdf]

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2601
Comment Excerpt Number: 3

Commenter Name: A. Steven Young
Commenter Affiliation: Association of Independent Corrugated Converters
Document Control Number: EPA-HQ-OAR-2002-0058-2899.1
Comment Excerpt Number: 1

Comment: New and overly stringent standards for industrial boilers will have an immediate impact on the independent corrugated converter's bottom line without demonstrated environmental benefits. Compliance costs associated with these harsh and inflexible proposed rules will cost U.S. manufacturing jobs and hurt global competitiveness, just as the economic recovery attempts to gain more traction. Further, as described below, the severity of the proposed standards are disincentives to projects that otherwise would realize environmental improvements.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2601
Comment Excerpt Number: 3

Commenter Name: Russell Wanke
Commenter Affiliation: Thilmany Papers
Document Control Number: EPA-HQ-OAR-2002-0058-3185.1
Comment Excerpt Number: 1

Comment: Our business, like many others, encounters many challenges. However, none threaten the continued existence of our business like the proposed Boiler MACT and CISWI rules. Why are these proposed rules a significant threat?
We estimate it will take $45 million in capital to comply. This is equivalent to 4 to 5 years of our normal total capital spend. When taking into account that a portion of our capital must be spent just to maintain operations, the compliance capital is equivalent to nearly 10 years of "growth and improvement" capital. Simply put, the millions we spend to become compliant with the proposed rules will replace investment needed to maintain competitiveness with competitors around the world who are not subject to the proposed rules.

In addition to the capital investment required to become compliant, we estimate that the ongoing incremental annual operating costs of the mandated controls will be in the $4 to $6 million range. We will be unable to pass these additional costs on to our customers as we face European and Asian competition (where the EPA proposed rules of course do not apply).

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2601
Comment Excerpt Number: 3

Commenter Name: Christopher S. Bond
Commenter Affiliation: United States Senator
Document Control Number: EPA-HQ-OAR-2002-0058-2958.1
Comment Excerpt Number: 1

Comment: U.S. Environmental Protection Agency (EPA) regulations proposed for industrial boilers and incinerators as applied to biomass-powered forest products facilities threaten to hurt both the environment and jobs. I urge you to consider instead cost-effective and achievable standards that protect human health.

Families and communities across Missouri depend upon the forest products industry for their livelihood. These are good people who work hard for modest wages across the 14 million forested acres in Missouri. Seventy-four percent of the energy needs of their employing sawmills come from their wood by-products. Woody biomass is not only an affordable fuel, it is also a renewable fuel that is lower in greenhouse gas emissions than alternative energy sources like coal-fired electricity or propane fired boilers. Those operations that do not use their own woody byproducts sell them to others, providing up to 15% of a sawmill's income. This value as a fuel or income source is often the difference between profitability and layoffs or closure.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2601
Comment Excerpt Number: 3

Commenter Name: David G. Koster
Commenter Affiliation: Holland Board of Public Works
Document Control Number: EPA-HQ-OAR-2002-0058-2907.1
Comment Excerpt Number: 1

Comment: We will face a disproportionate impact under the proposed rule that will threaten our ability to provide necessary public services.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2418.1
Comment Excerpt Number: 4

Commenter Name: Cindy Eveler
Commenter Affiliation: Lincoln Area Chamber of Commerce
Document Control Number: EPA-HQ-OAR-2002-0058-3206
Comment Excerpt Number: 1

Comment: The Lincoln Area Chamber of Commerce is greatly concerned over EPA's Proposed Boiler MACT rule and the implications therein that would significantly burden, and have the potential to limit or shut forest products industry boiler and cogeneration facilities. The continued effect to provide steam or electricity to the industry via non-wood/biomass only add cost burden and dependence on fossil and foreign fuels – both of which further limit the viability of the wood-products industry.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2601
Comment Excerpt Number: 3

Commenter Name: Christopher S. Colman
Commenter Affiliation: Hovensa LLC
Document Control Number: EPA-HQ-OAR-2002-0058-2863.1
Comment Excerpt Number: 1

Comment: The refinery location in the USVI results in several major differences from most mainland refineries and raises issues that are unique, but similar to those facing other remote and island major sources. HOVENSA's St. Croix refinery does not generate enough refinery fuel gas to meet all of its energy needs, and does not have access to a natural gas pipeline, as do all but a few mainland refineries. HOVENSA has no economically practical alternative to using residual fuel oil for an energy source, because the use of high cost distillates would have devastating economic impacts on HOVENSA. Equally important, the island location and the lack of a local reliable electricity grid or water supply mean that HOVENSA must be entirely self sufficient for steam, electricity and desalinated water. This magnifies the effect of Boiler MACT on HOVENSA, because HOVENSA must build and operate the utilities that most other major sources have access to by virtue of their location.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2418.1
Comment Excerpt Number: 4

Commenter Name: Al Hankins, Jr.
Commenter Affiliation: Hankins Lumber Company, LLC
Document Control Number: EPA-HQ-OAR-2002-0058-2708.1
Comment Excerpt Number: 1

Comment: If this rule is finalized in its current form, we believe operations like ours may simply disappear. None of us can afford to invest millions of dollars in 3 or 4 new types of control equipment.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2418.1
Comment Excerpt Number: 4

Commenter Name: Duane Mummert
Commenter Affiliation: South Carolina Chamber of Commerce Environmental Technical Committee
Document Control Number: EPA-HQ-OAR-2002-0058-3171
Comment Excerpt Number: 1

Comment: South Carolina industry faces a withering global economic slump and fierce competition from overseas manufacturers. Therefore, it is imperative for mandatory environmental controls such as the Industrial Boiler MACT standard to be tailored as closely as possible such that health and the environment are protected without requiring unnecessary expenditures of time and resources.

At a time when our economy is fragile and our country faces almost 10% unemployment, the government is adding a significant layer of costs for industry that will close additional manufacturing operations and businesses, and cost thousands of additional jobs by setting limits that are sharply below health-based protection thresholds.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2601
Comment Excerpt Number: 3

Commenter Name: Paul N. Cicio
Commenter Affiliation: Industrial Energy Consumers of America
Document Control Number: EPA-HQ-OAR-2002-0058-2752.1
Comment Excerpt Number: 1

Comment: Cost and jobs implications of the Boiler MACT
We cannot emphasize more forcefully the need to the EPA to completely re-think this rule. As written, it threatens countless companies to spend millions of dollars per boiler and many companies have multiple boilers – all without any financial benefit and at a time they can least afford it. This means that when companies are forced to spend capital on projects that do not create value, there is less capital available to hire workers, invest in energy efficiency, R&D etc.

As currently crafted, the Boiler MACT will result in a combination of undesirable outcomes including: enormous unproductive use of limited capital without financial benefit, higher operating costs that impact global competitiveness, increased annual fuel and electricity costs, less facility operating flexibility, the shutdown of the entire facility (not just the cogen unit), and if they shut down their cogeneration facility, higher electricity costs and net emissions.
In this fragile economic recovery, it is deeply troubling to consider the combined effects of tightening the National Ambient Air Quality Standards, Regional Haze, regulation of Greenhouse Gases under the Clean Air Act, and this proposed Boiler MACT rule. Companies are very concerned that they will not be able to pass these substantial costs on without losing significant market share to foreign competition.
The manufacturing sector is barely hanging on - running at production rates that are between 50-60% of capacity. As such, many of these facilities are “on-the-margin” which means they are either not profitable or marginally profitable because of the economic downturn. We are enormously concerned that the high costs of this proposed rule will leave companies no recourse but to shut down the entire facility, not just the boiler. This is due to the fact that many manufacturing sites require steam to heat processes and electricity to operate equipment. This is the primary reason that combined heat and power plants / co-generation facilities are so effective. Many of the facilities supply incremental amounts of electricity to the grid which enhances that system. If these shutdown then it will lead to greater dependence on the utility sector and less diversity in how power is supplied. If sites do not need the process steam and cannot afford the controls required by this action and shut down their cogeneration facility, they have no recourse but to buy high emission electricity from their local utility.
To further complicate things, since about 2000, the US manufacturing sector has consistently lost competitiveness versus competitors offshore. This means that the cost of operating in the US is higher than the cost of producing the same product in another country. Clear benchmarks are employment, investment and export/imports. Since 2000, the US manufacturing sector has lost almost 6 million jobs or 32%, investment as a percent of GDP is only about 2/3’s what it has been from 1980 to 2000 and our trade deficit has ballooned. The loss of 6.0 million manufacturing jobs at $48,266 per employee has also resulted in lost payroll of almost $289 billion per year and lost federal taxes of about $38 billion. Sadly, there is no indication that these trends have bottomed out and are beginning to turn favorably.
Despite these gloomy numbers, in 2009, the manufacturing sector contributed about $1.6 trillion value-added to the economy, provides 58% of US exports, employs 12 million people and spends $160 billion each year on domestic R&D. And, there is a growing recognition by Congress that a healthy growing export focused manufacturing sector is critically vital to the future of our nation’s economic and national security. However, to achieve these national goals, it is critically important that the EPA not impose unnecessary costs and must take great care to increase flexibility under this rule.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-3193
Comment Excerpt Number: 1

Commenter Name: Karen S. Price
Commenter Affiliation: West Virginia Manufacturers Association
Document Control Number: EPA-HQ-OAR-2002-0058-2957.1
Comment Excerpt Number: 1

Comment: The WVMA is very concerned regarding the effects of the proposed rule on its members. This proposal is very far reaching and it is estimated that it would affect 1600 facilities and 13,555 boilers including 11,500 gas fired boilers across the country. This estimate includes the following sectors: 350 chemical manufacturing, 250 wood product manufacturing, 150 transportation equipment manufacturing, 125 food manufacturing, 100 fabricated metal product manufacturing, 75 pipeline transportation, 75 petroleum and coal products manufacturing, 75 primary metals manufacturing and 50 educational services facilities.
Not only are the proposed rules overly far reaching, the proposed rules will impose very stringent emission limits, monitoring and testing requirements for particulate matter, hydrochloric acid, mercury, carbon dioxide and dioxin. The emission limits for affected units will be based on fuel type and boiler design. To achieve the requirements of the proposed rules, industry will have to install multiple controls and complex monitoring systems. It is estimated that industry will,have to spend over $21 billion dollars in capital costs and close to $50 billion in on-going experiditures to comply with the proposed rules.
The proposed rules potentially impose tens of billions of dollars in capital costs and threaten job losses at thousands of industrial, municipal, university, federal and commercial facilities across the country. We are particularly concerned in West Virginia, where our manufacturing industry has suffered greatly in response to the changes in the regulatory climate and recent recession. It is anticipated that our already stressed members will be severely affected by the proposed Industrial Boiler MACT.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2601
Comment Excerpt Number: 3

Commenter Name: Allyn Ford
Commenter Affiliation: Roseburg Forest Products
Document Control Number: EPA-HQ-OAR-2002-0058-3163
Comment Excerpt Number: 1

Comment: Initially, it is surprising that the federal government would propose such an extremely stringent, costly rule that will undoubtedly stifle industrial growth and operations at a time when the economy is so dismal. The national unemployment rate continues to hover around 10%, with the manufacturing sector and supporting industries being amongst the hardest hit. The impact from this rule, especially during these difficult economic times, may prove to be unsustainable; further eroding manufacturing operations and the jobs they create, as costs to individual facilities could easily be tens of millions of dollars. Since similar regulations are not being imposed anywhere else in the world, U.S. manufacturing will be put at an even worse competitive disadvantage. To further compound the situation, manufacturing in this country will become more expensive which will result in our exportation of jobs and pollution to other countries where less stringent requirements apply and dirtier fuels will likely be used to make the same product. Accordingly, any decrease in emissions resulting from this rule will be more than offset by uncontrolled, increased overseas manufacturing along with the emissions associated with shipping those foreign goods from the point of origin to the United States.

Response: The EPA used a standard market analysis to analyze the proposed MACT standards. The approach uses a single period multimarket partial equilibrium model to compare pre-policy market baselines with expected post-policy market outcomes. The analysis' time horizon is the intermediate run; some production factors are fixed and some are variable and is distinguished from the very short run where all factors are fixed and producers cannot adjust inputs or outputs. The intermediate time horizon allows us to capture important transitory stakeholder outcomes. Key measures in this analysis include industry-level changes in price levels, production and consumption, jobs, international trade, and social costs (changes in producer and consumer surplus). The analysis did not show large changes in production, prices, or imports.

Commenter Name: Paul Machtolf
Commenter Affiliation: Ponderay Newsprint Company
Document Control Number: EPA-HQ-OAR-2002-0058-2712.1
Comment Excerpt Number: 1

Comment: The domestic market for newsprint has declined from 10 million metric tons in 2001 to just 4.8 million today. In 2009, Ponderay Newsprint Company experienced market downtime, and employee benefit and headcount reductions. It has been estimated that the proposed Boiler MACT standards would require a $5 million modification to the fluidized bed boiler that cost $8 million to install and that already has Title V-approved pollution control equipment.

EPA has the legal discretion and technical justification to substantially reduce the burden of the standard, while still providing ample protection to health and the environment, and we urge you to do so.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2418.1
Comment Excerpt Number: 4

Commenter Name: Edward J. Wilusz
Commenter Affiliation: Wisconsin Paper Council
Document Control Number: EPA-HQ-OAR-2002-0058-3185.2
Comment Excerpt Number: 1

Comment: Wisconsin's pulp and paper industry faces a challenging global economic slump and fierce competition from overseas manufacturers. This situation has existed for the past ten years. Mills in Port Edwards, Niagara, Neenah, Menasha, and Kimberly have closed during that time. In the last ten years paper industry employment in Wisconsin has dropped from 52,000 to 32,000. That's over $1 billion in annual wages lost.
We are concerned that compliance with EPA's proposed boiler MACT standards will be extremely expensive, if compliance can be achieved at all. EPA's estimated capital costs of $9.5 billion, a staggering estimate in its own right, appears to be low. Industry capital cost estimates for the forest products sector alone are estimated to be $6.8 billion. The estimated costs for Wisconsin are $680 million, with $470 million born by the forest products industry.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2601
Comment Excerpt Number: 3

Commenter Name: Paul N. Cicio
Commenter Affiliation: Industrial Energy Consumers of America
Document Control Number: EPA-HQ-OAR-2002-0058-2752.1
Comment Excerpt Number: 2

Comment: The EPA must not underestimate the seriousness of our concerns. We have solicited comments from a few of our companies of their estimated cost of compliance. The survey makes it clear why we are concerned.
1. A food processing facility: The cost of compliance for their biomass conversion cogeneration facility is $7 . 5 million. If that becomes the actual cost, consideration would have to be given to shutting down the plant and buying electricity from a utility which would increase their electricity costs and net emissions.
2. A chemicals and paper producer: The capital cost estimate for all US facilities are $600 million plus higher operating costs. That does not include costs associated with the issue of the "Definition of Solid Waste rule". They said that low-margin facilities could be closed rather than spend a lot of capital.
3. A food processing facility: Estimated capital costs for each of their three locations to be between $17 and $41 million and an increase in operation costs of $20 to $37 million over 20 years.
4. A paper producing company: Engineering estimates indicate capital expenditures of around $48.5 million to $116 million plus $1.82 million to $6.5 million in additional annual operating costs. They said these costs are significant and have the potential to put this company at a distinct disadvantage as they compete in a global marketplace. The impact of these costs, will put mills and jobs "at risk" when costs exceeded mill's cost-ofproduction by more than a sustainable amount and cash flow turns negative.
5. A chemical company: The company uses its boilers to self-generate power and steam by combined heat and power that delivers energy and efficiencies well above those achievable by

electric utilities. Estimated capital cost of $97 million to retrofit more than a dozen domestic boilers plus additional control of acid gas emissions add an additional $200 million of capital expenditures. The operating and maintenance costs are estimated at approximately $24 million per year.
6. Aspecialty chemical manufacturer: The Boiler MACT is going to cost about $8 million in capital costs and a minimum of $1 million of annual operating cost going forward.
7. A manufacturer: Capital cost estimate of $10 to $30 million and operating cost in the range of $2 to $ 5 million annually. The loss of dual fuel negotiating position would jeopardize the current favorable transport fee for natural gas of $450K per year and increase costs up to $1.65 million dollars per year. Also, the MACT cost could cause them to retire one boiler and purchase electricity from an electric utility, increasing their electricity costs and resulting in higher emissions.
8. A chemical and paper producer: Total capital cost for the 4 facilities is estimated to be $26 to $40 million plus higher operating costs.
9. A commodity and specialty chemical company: Total capital costs for three boilers are $100 million with increased operating costs of over $1 million annually that puts the jobs of 500 employees at risk. With the health based compliance alternative, the capital costs would drop to about $20 million.
On top of all of the above, this rule will result in significant fuel switching from coal, a reliable, low cost and low price volatile fuel, to natural gas, a high cost and very price volatile fuel. According to the EIA, the average cost of Appalachian coal from 2000 to 2008 was only $1.48 per mmBtu while natural gas was $6.10 per mmBtu - four times more expensive than coal. Natural gas is also the most volatile commodity in the world. The charts at the end of this report illustrate that natural gas is more than twice as volatile as coal which results in higher costs for industrial consumers.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2418.1
Comment Excerpt Number: 4

Commenter Name: Robert E. Cleaves
Commenter Affiliation: Biomass Power Association
Document Control Number: EPA-HQ-OAR-2002-0058-2934.1
Comment Excerpt Number: 2

Comment: We are concerned that the proposed rules will impose tens of billions of dollars in capital costs at thousands of facilities across the country. Thus, we ask EPA to consider flexible approaches that appropriately address the diversity of boilers, operations, sectors, and fuels that could prevent severe job losses and billions of dollars in unnecessary regulatory costs.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-3193

Comment Excerpt Number: 1

Commenter Name: Steven W. Koehn
Commenter Affiliation: National Association of State Foresters
Document Control Number: EPA-HQ-OAR-2002-0058-2860.1
Comment Excerpt Number: 2

Comment: The forest products industry is vital to our Nation's economy. Despite the recent economic downturn
and significant job loss in the sector, the forest products industry employs nearly 1 million workers, and is among the top 10 manufacturing employers in 48 states. The industry alone is responsible for 6% of the Nation's gross domestic product, and is capable of more.[FOOTNOTE: Hunt, T. 2010. Testimony on behalf of AF&PA provided at EPA Hearing on Boiler MACT. Last accessed on-line on August 18, 2010 at: http://www.afandpa.org/whatwebelieve.aspx?id=532] Alongside the forest products industry is the emerging forest biomass markets that can help improve the management on public and private forest lands. Forest biomass provides a clean and inexpensive form of fuel that is often used by hospitals and public institutions as fuel for steam heating. We hold concerns that the proposed regulations can significantly increase costs for those who supply and consume biomass. High compliance costs for biomass will result in less use of biomass in boilers, limiting the market for biomass and making most biomass boiler projects uneconomical.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2601
Comment Excerpt Number: 3

Commenter Name: Arthur Blazer
Commenter Affiliation: Council of Western State Foresters
Document Control Number: EPA-HQ-OAR-2002-0058-2832.1
Comment Excerpt Number: 2

Comment: The forest products industry is vital to our Nation's economy. Despite the recent economic downturn
and significant job loss in the sector, the forest products industry employs nearly 1 million workers, and is among the top 10 manufacturing employers in 48 states. The industry alone is responsible for 6% of
the Nation's gross domestic product, and is capable of more. [Footnote: Hunt, T. 2010. Testimony on behalf of AF&PA provided at EPA Hearing on Boiler MACT. Last accessed on-line on August 18, 2010 at: http://www.afandpa.org/whatwebelieve.aspx?id=532] Alongside the forest products industry is the emerging forest biomass markets that can help improve the management on public and private forest lands. Forest biomass provides a clean and inexpensive

form of fuel that is often used by hospitals and public institutions as fuel for steam heating. We hold concerns that the proposed regulations can significantly increase costs for those who supply and consume biomass. High compliance costs for biomass will result in less use of biomass in boilers, limiting the market for biomass and making most biomass boiler projects uneconomical.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2601
Comment Excerpt Number: 3

Commenter Name: Steve Zika
Commenter Affiliation: Hampton Lumber Mills, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2817.1
Comment Excerpt Number: 2

Comment: Hampton has done a significant amount of work evaluating the proposed rules and emission limits and engaged the services of consultants to determine the costs for infrastructure modifications necessary to meet the proposed standards. Our consultants used actual source test data from our boilers, fuel analysis, and obtained estimates from emission control vendors. If the proposed standards for HCL, Mercury, and Dioxin/Furans remain as they are in the proposed Major Source rules, Hampton will be faced with capital improvements in excess of $10 million, with at least $2.5 million dollars in additional annual operating costs. Our customers, including Home Depot and Lowes, are not going to pay us any more for our lumber to reimburse us for these costs. They may simply decide to purchase less expensive lumber from a supplier outside of the United States.

In the past five years, Hampton and our employees have already had to make significant financial sacrifices to continue to operate our mills and modernize equipment to remain a viable company. Soaring health care costs, rising fuel prices, and the global housing recession all create very challenging times ahead. The news regularly reports the curtailment or the sale and demolition of sawmills throughout the United States and Canada. I believe that the impact of the regulatory burden and financial expenditures from your proposed regulations will cause more mill closures and loss of jobs in rural communities in Oregon and Washington.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2418.1
Comment Excerpt Number: 4

Commenter Name: Joseph M. Cloutier
Commenter Affiliation: RE-Gen, LLC
Document Control Number: EPA-HQ-OAR-2002-0058-3211.1

Comment Excerpt Number: 2

Comment: RE-Gen is concerned that the EPA's proposed rules will:

Reduce our ability to grow energy jobs through new companies like RE-Gen, LLC and Renewable Energy Fuels, LLC

Stall or diminish the ability for RE-Gen and/or its clients to develop projects.

Result in the closure of existing plants and possibly stop the growth of this industry

Response:
See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2601
Comment Excerpt Number: 3

Commenter Name: Ron Lindsey
Commenter Affiliation: Packaging Corporation of America
Document Control Number: EPA-HQ-OAR-2002-0058-3158
Comment Excerpt Number: 2

Comment: In the past 15 years, many paper mills have closed across the country due to economic conditions, including some here in Georgia. Others in Georgia, North Florida and many other states are barely hanging on. Some mills have been down almost as much as they have operated in the last 2 years. Even when a facility has not shut down, it may have reduced its operations. Our company shuttered one paper machine in 2005 that cost union jobs. The paper industry competes in a global market place, and if costs are increased unnecessarily, we cannot succeed. My co-workers, my family, and I are increasingly anxious as we worry about the future of our industry and our jobs. Other good paying jobs are hard to find, especially in the rural areas where we operate, so when a paper mill, or even a paper machine, is shut down, the impact to a family due to job loss is immense. Our communities also suffer when mills close – the tax base shrinks, loggers lose their primary customer and other area businesses that support the mills lose a large part of their sales. And with the loss of jobs often comes reduced health care benefits, which carries a far greater public health risk than the emissions from an already well controlled boiler.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2601
Comment Excerpt Number: 3

Commenter Name: Bill Perdue
Commenter Affiliation: American Home Furnishings Alliance
Document Control Number: EPA-HQ-OAR-2002-0058-2692.1
Comment Excerpt Number: 3

Comment: If dry biomass combustion units are included in a generic biomass category, many (if not all) of the remaining domestic operators will be forced to make a decision: either switch to package natural gas boilers – if natural gas is locally available – or discontinue domestic operations and send production overseas.

In today's economic climate, no furniture manufacturer will elect to invest significant capital and commit to increased operating expenses to install a control device of the type that would be required under the rule as written. We will use a typical North Carolina wood furniture manufacturing facility to illustrate the projected costs and negative issues associated with the rule as proposed. This facility operates two dry wood-fired boilers rated at 46.7 MMBTU/hr each, typical of the smaller boilers operated by our industry. The boilers provide process steam heat for the finishing line drying ovens and space heat for the multiple buildings that comprise the manufacturing facility. Total wood fuel consumption for the combined boilers is approximately 12,000 tons per year.

In the preamble to the proposed rule, the EOPA states that MACT for a boiler like the one at our example facility will comprise a fabric filter (for metals) with carbon injection (for dioxins and furans) plus a wet scrubber (for HCl), plus combustion improvements or a CO catalyst (for organic HAP). Furniture manufacturing boilers rarely have any of these types of control equipment, and the example facility is no exception. The existing units could not meet proposed MACT limitations as currently categorized, so we will reasonably assume that the EPA is accurate in its depiction of the control devices that would be necessary to meet MACT for the facility boilers. Assuming that a single set of control devices can service both boilers, the projected capital cost for MACT control equipment at the example facility is calculated using the AF&PA protocol as follows: $1,000,000 for a fabric filter (AHFA). $1,000,000 for carbon injection (AF&PA), $4,431,000 for a single wet scrubber (AF&PA).

The total estimated capital cost of $6,431,000 assumes that a CO catalyst will not be required, and that a single set of units can be located to service two combined stacks; operating costs are not included in this analysis. The projected cost of add-on controls will force every wood furniture manufacturer to evaluate discontinuing use of the carbon-neutral dry biomass and switching to the fossil fuel natural gas (assuming natural gas is available at the facility location). Instead of recovering energy from the dry biomass, it will probably be landfilled. Based on today's landfill fees, it is projected that the manufacturer would incur an additional annual cost of $528,000 to landfill the renewable fuel. In addition to the landfill fees themselves, the manufacturer would incur additional annual costs of $137,000 to transport the fuel to the landfill. Replacing the annual heat value in 12,000 tons of dry biomass would require 192,000 dekatherms of natural gas. At the current local spot market price of $5.50 per dekatherm, the additional fuel cost for natural gas would be approximately $1,100,000 per year. The resulting total annual projected cost of compliance for this facility would be $1,765,000, not including one-time costs associated with boiler refitting for natural gas and construction to provide gas line access to the facility.

The ultimate result of the proposed rule will be to force this facility and many others like it to shift production and jobs overseas.

It is impossible to avoid the conclusion that the proposed rule would have a profoundly negative effect on the wood furniture manufacturing industry. However, the negative effect goes beyond our industry alone and directly contradicts two key initiatives of the current administration: controlling greenhouse gas emissions, and decreasing our nation's foreign trade deficit.

Response:
See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2601
Comment Excerpt Number: 3

Commenter Name: Allyn Ford
Commenter Affiliation: Roseburg Forest Products
Document Control Number: EPA-HQ-OAR-2002-0058-3163
Comment Excerpt Number: 3

Comment: Direct costs to the forest products industry associated with this rule are expected to be in the neighborhood of $6 to 7 billion over the next two to four years. These are costs imposed on an industry that made roughly one billion dollars during each of the last two years. The outcome of these costs will be further job losses, on top of the 350,000 jobs that have been lost in this sector since 2006.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2601
Comment Excerpt Number: 3

Commenter Name: James Johnson
Commenter Affiliation: U.S. Beet Sugar Association
Document Control Number: EPA-HQ-OAR-2002-0058-2827.1
Comment Excerpt Number: 3

Comment: Future operations of member's facilities may be seriously jeopardized due to constraints imposed on fuel flexibility and future availability of fuels.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2601
Comment Excerpt Number: 3

Commenter Name: Linda Barnfather
Commenter Affiliation: Washington House of Representatives
Document Control Number: EPA-HQ-OAR-2002-0058-2852.1
Comment Excerpt Number: 3

Comment: In 2006 the state energy freedom fund provided $6 million to the Grays Harbor PUD to invest in a new biomass boiler used by the Grays Harbor Paper Company to generate process steam for the 100% recycled green paper plant and electrical power for the PUD. [Footnote: http://www.commerce.wa.gov/DesktopModules/CTEDPublications/CTEDPublicationsView.aspx?tabID=0&ItemID=6698&MId=863&wversion=Staging]
In 2009 the Port Townsend Paper Company received a $2 million dollar stimulus grant to upgrade its biomass boiler. This grant is being matched by $2 million in private funds generated by other energy saving projects in the mill. This boiler is now a part of a proposed $55 million cogeneration project that will provide the equivalent of 35 construction jobs for one year and will create 30 new jobs. In addition, it helps sustain the 290 permanent mill jobs.
Also in 2009, the Nippon Paper Company in Port Angeles received a combination of loans and grants of $2 million to support a planned $71 million investment to replace an existing steam boiler with a biomass boiler retaining 234 permanent jobs and adding 10 temporary jobs. [Footnote: http://www.commerce.wa.gov/site/1345/default.aspx]

A 2009 state study on pulp and paper boilers showed great opportunities for reduced fossil fuel usage and increased renewable energy production – but old boilers will need to be upgraded. [Footnote: http://www.chpcenternw.org/NwChpDocs/Pulp_and_Paper_EE_Boilers_and_CHP_092009.pdf]

With the capital costs involved and the current state of the market, it would be unfortunate if limited capital resources went into short term investments to meet unattainable standards rather than a longer term strategy of investing in aging infrastructure that can continue to create jobs and meet core business objectives while increasing renewable energy generation and environmental performance.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2601
Comment Excerpt Number: 3

Commenter Name: James C. Jackson
Commenter Affiliation: Boise, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2855.1
Comment Excerpt Number: 3

Comment: A single unifying theme lies at the heart of our comments on the proposed Boiler MACT rule — the proposed standards are far more stringent than needed to assure protection of health and the environment from industrial boiler HAP emissions and to fully meet EPA's obligations under the Clean Air Act. During the recent severe economic downturn, Boise was forced to close a pulp mill and two uncoated freesheet paper machines and indefinitely curtail operation of a newsprint machine resulting in about 430 direct jobs lost or about 9% of our workforce. Further economic pressures are expected due to fierce competition from overseas manufacturers as well as an onslaught of regulatory activity Therefore, it is imperative for mandatory environmental controls such as the Boiler MACT standard to be designed such that human health and the environment are protected without requiring unnecessary expenditures of time and resources.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2418.1
Comment Excerpt Number: 4

Commenter Name: Ted Michaels
Commenter Affiliation: Energy Recovery Council
Document Control Number: EPA-HQ-OAR-2002-0058-2831.1
Comment Excerpt Number: 3

Comment: EPA's stringent standards will have negative consequences on the beneficial use of secondary biomass materials, requiring significant investment and operating costs on biomass-to-energy plants that already meet health-based standards. These plants use forest, agricultural and urban-derived wood residues to produce renewable energy, managing materials that would otherwise be landfilled or open-burned. The plants in California already meet the State's stringent health-based toxic air emission standards. Take, for example, Covanta Energy Corporation's Oroville, California facility which combusts urban demolition wood and agricultural wood and residues, producing 20 MW of renewable electricity. The plant employs 24 people from the surrounding small communities and contributes $13 million dollars annually to the local economy. Since 1987 the facility has been subject to California's AB 2588 Air Toxics "Hot Spots" Program which requires assessments of the health risks of emissions of hazardous or toxic air pollutants. The AB 2588 program provides for the calculation of the cancer, chronic non-cancer, and acute non-cancer risks due to emissions from any specific facility, based on measurements of the toxic emissions from that facility, using an approved methodology, with the comparison of the results to established thresholds of acceptable risk. This program, a "Health Risk Assessment (HRA)," has been successfully and effectively employed in California for over two decades. Recently, the Butte County Air Quality Management District (BCAQMD) reported the results of its AB 2588 assessment for the Oroville facility, indicating a potential cancer risk of 0.42 in a million and chronic and acute hazard indices of 0.005 and 0.003 respectively.[Letter from David J. Lusk, Senior Air Quality Engineer, BCAQMD to Francisco Barriga dated March 12, 2010.] Cancer risks of less than one in a million and hazard indices of less than one are deemed acceptable by the BCAQMD. Risks are also below EPA's acceptable carcinogenic risk threshold range of 1 to 100 in a million. As this example shows, EPA's proposed standards would impose unnecessary and costly emission reduction requirements on biomass-to-energy facilities that currently meet applicable health-based standards.

Response:
See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2601
Comment Excerpt Number: 3

Commenter Name: A. Preston Howard, Jr
Commenter Affiliation: Manufacturers and Chemical Industry Council of North Carolina
Document Control Number: EPA-HQ-OAR-2002-0058-2706.1
Comment Excerpt Number: 4

Comment: Most of our State's industries are working hard to keep their plants open and keep their people employed in the current sagging economy. With unemployment figures hovering around 10%; federal, state, and local governments struggling to maintain fiscal stability; and severe limitations on capital project financing; it is difficult to imagine a more inopportune time for EPA to be imposing such a costly rule.
MCIC supports efforts to address serious health threats from air emissions and believes EPA can craft regulations that sustain both the environment and our competitive position in the world marketplace, while maintaining jobs for the more than 500,000 men and women that are currently employed in manufacturing here in North Carolina. Unfortunately, implementation of EPA's proposed Boiler MACT, as currently proposed, will work at odds with our collective efforts to reverse the current trend in job loss.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2601
Comment Excerpt Number: 3

Commenter Name: Christopher S. Bond
Commenter Affiliation: United States Senator
Document Control Number: EPA-HQ-OAR-2002-0058-2958.1
Comment Excerpt Number: 4

Comment: EPA's proposed rules also threaten the ability of struggling families and communities to protect and create jobs. Many parts of rural Missouri, ideal places for the growth and use of biomass, are struggling mightily in the current hard economic times. Rural workers just cannot handle more bureaucratic and expensive regulations from Washington that kill jobs instead of create them. Experts estimate EPA's proposed regulations will cost the forest products industry $7 billion. Killing just one job unnecessarily is not only unfair to struggling workers, it is unconscionable. The administration can hardly claim it cares about job creation if it finalizes regulations as proposed by EPA in this case.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2601
Comment Excerpt Number: 3

Commenter Name: Nina E. Butler
Commenter Affiliation: Smurfit-Stone Container Corp.
Document Control Number: EPA-HQ-OAR-2002-0058-2783.1
Comment Excerpt Number: 4

Comment: The extraordinarily high costs of complying with the Proposed Boiler MACT come at a time of great economic difficulty in the United States. In Smurfit-Stone's case, the company emerged from bankruptcy on June 30, 2010 after 17 months of financial restructuring, and we are continuing to strive to improve our profitability.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2418.1
Comment Excerpt Number: 4

Commenter Name: Ron Lindsey
Commenter Affiliation: Packaging Corporation of America
Document Control Number: EPA-HQ-OAR-2002-0058-3158
Comment Excerpt Number: 5

Comment: Our company relies on coal-fired boilers for low-cost energy; almost half of our company's energy supply for our industrial boilers comes from coal. Being a low-cost producer is how paper mills survive – that's what keeps us in operation. Yet the proposed rule could possibly result in the shut down some of our coal-fired boilers, which would threaten our company's competitiveness and put our jobs at risk.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2418.1
Comment Excerpt Number: 4

Commenter Name: Lynn D. Westfall

Commenter Affiliation: Tesoro Companies
Document Control Number: EPA-HQ-OAR-2002-0058-2846.1
Comment Excerpt Number: 5

Comment: If liquid-fired sources in locations without a natural gas supply are not exempted from the proposed BPH rule emission standards and allowed to follow an alternative work practice standard, Tesoro would likely not be able to continue operating its Kapolei Refinery. The closure of this refinery would make the fuel supply to local electrical generation plants less dependable, which could affect both the availability and the price that consumers pay for power.

While motor fuels could potentially be transported from the mainland to supply Hawaiian consumers, the added transportation costs would make those fuels more expensive. Tesoro is also a major fuel supplier to military installations in Hawaii. The cessation of refinery operations could adversely impact the fuel supply for military operations in this region.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2418.1
Comment Excerpt Number: 4

Commenter Name: Linda Barnfather
Commenter Affiliation: Washington House of Representatives
Document Control Number: EPA-HQ-OAR-2002-0058-2959
Comment Excerpt Number: 5

Comment: We are deeply concerned over the potential impact on our businesses, jobs and the biomass industry.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-3193
Comment Excerpt Number: 1

Commenter Name: Douglas J. Van Pelt
Commenter Affiliation: ExxonMobil
Document Control Number: EPA-HQ-OAR-2002-0058-2968.2
Comment Excerpt Number: 5

Comment: EPA has inappropriately used opinions of selected experts in an economic analysis

In this RIA as in many recent RIAs where EPA considers the benefits of PM reductions, EPA used the results of an Expert Elicitation (EE) effort (Roman et al., 2008) effort as a direct input for the critical CRF for chronic mortality to quantify the economic benefits of PM reductions. First, it is inappropriate to substitute the opinion of any individual expert for actual scientific data or fact for use in a quantitative economic assessment. Second, the EE published by Roman et al. was sponsored and administered by EPA, introducing a potential policy oriented bias. As described below, the process used to select the experts and to elicit these opinions was clearly biased.

Our view on the current status of EE is consistent and supported by the recommendations of the National Research Council Committee on Improving Risk Assessment Approaches (CIRAA), a committee commissioned by EPA for the purpose of providing advice on improving risk assessment at EPA (NRC,2008). In the chapter on uncertainty and variability, the CIRAA express serious concerns with both the methodology and use of EE. This discussion was provided in the context of the specific EE report on PM which the Committee used as an example to express their concerns. This text appears on pages 93-95 of the report.

First, the CIRAA did not consider the information from the EPA PM EE report to be useful for weighing risk management options.

"Expert elicitation can provide interesting and potentially valuable information, but some critical issues remain to be addressed. It is unclear precisely how EPA can use this information in its risk assessments. For example, in its regulatory impact analysis of the National Ambient Air quality standard of PM2.5, EPA did not use the outputs of the expert elicitation to determine the confidence interval for the concentration-response function for uncertainty propagation but instead calculated alternate risk estimates corresponding to each individual expert's judgment with no weighting or comparing of judgments (EPA, 2006). It is unclear how that type of information can be used productively by a risk manager, inasmuch as it does not convey any sense of the likelihood of various values, although seeing the range of commonality of judgments of individual experts may be enlightening."

The CIRAA expressed serious reservations concerning the underlying cognitive tendencies that influence expert judgment and which cannot be accounted for. The reservations expressed by CIRAA are listed below, along with our comments on how they apply in the case of the EPA EE effort.

availability: the tendency to assign greater probability to commonly encountered or frequently mentioned events

EPA has placed high importance on chronic PM mortality in previous NAAQS reviews. The expert EE panel members were clearly aware of this fact, thereby introducing a bias to assign a higher probability to a commonly mentioned event.

anchoring and adjustment: the tendency to be over-influenced by the first information seen or provided in an initial problem formulation

In previous PM NAAQS reviews, EPA placed high importance on the results of the ACS study, a fact clearly known to the panel, especially since the panel included a number of co-authors of this study. EPA introduced further bias by emphasizing the ACS study in the background materials provided to the expert panel. EPA introduced the ultimate bias when they invited the lead author of the ACS study, Arden Pope, to make a presentation during the EE deliberations. The objective of the presentation was to address and dispel any limitations of the study that the experts may have had. All of these activities ensured that the ACS study would receive primary importance in the PM mortality risk estimates, thereby introducing serious anchoring and adjustment bias.

representativeness: the tendency to judge an event by reference to another that in the eye of the expert resembles it even in the absence of relevant information

disqualification: the tendency to ignore data or strongly discount evidence that contradicts strongly held convictions

EPA set up an expert selection process that was designed to maximize the number of experts on the panel engaged in the conduct of observational epidemiologists, with well know opinions on the key questions, which were: 1) are the association's causal (yes); 2) is there a threshold for the effects (no). This was achieved by basing the selection of the initial expert list on the number of publications. It is well known that is very easy to publish, for example, time-series observational air pollution studies. All one needs is access to publicly available air pollution and morbidity/mortality records and the standard programs to develop correlations between the two. Based on the pilot EE for which there was a different spectrum of experts and results, i.e., a higher percentage of those engaged in human clinical or toxicology research, EPA excluded most of these experts, who are known to have a higher tendency to have opinions different that than the "strongly held views". The few people who remained on the final panel with differing views were thereby marginalized, introducing a serious member disqualification bias. EPA then provided a list of studies that did not include those reporting no association between PM and mortality, or those suggesting that threshold for health effects may actually exist, depending on the methodology of analysis used. EPA thereby disqualified these studies from consideration.

belief in law of small numbers: the tendency of scientists to believe small samples form a population to be more susceptible than is justified

Based on review of the various science documents EPA has recently produced for criteria pollutants, we conclude that EPA now assumes that there exists for all criteria pollutants no threshold below which at least some individual may be affected by exposure. We term this the EPA doctrine of "infinite population susceptibility." The new causality scheme EPA has adopted for NAAQS reviews places unqualified high emphasis on the results of observational epidemiology studies of air pollution. These studies report very small relative risks that are 2 to 3 orders of magnitude below those that would normally be required to support causality. EPA continues to confuse these small relative risks reported in the studies themselves from observational epidemiology studies, with larger potential population risks derived from their risk assessment process, which are based on exposure to the general population. Therefore, we conclude that EPA has a near unqualified belief in the law of small numbers.

overconfidence: the tendency of experts to overestimate the probability that their answers are correct. In our view, many of the scientists EPA included on the PM EE effort fall in the category of those inclined to overstate the confidence in observational epidemiology data in general, and specifically, the results of the studies EPA selected to consider in this effort. First, the panel consisted of a high percentage of experts conducting observational epidemiology studies. These panel members have a vested economic and professional interest in promoting these types of studies. We note that many of the panel members have received EPA funding, and EPA continues to provide extensive funding for observational epidemiology research. Second, many of the key studies that EPA selected to focus on were authored by the panel members or colleagues, e.g. trained or worked at the same university. Therefore, these experts were in many cases opining on their own data, or the data of colleagues, introducing a significant bias towards being less critical of the findings, resulting in overstating the confidence in the results.

Given the concerns expressed by the NRC CIRAA on the methodology and use of EE in risk assessment, they argued against using EE results either qualitatively for risk assessment or management.

"Given all these limitations, there are few settings in which expert elicitation is likely to provide information necessary for discriminating among risk-management options. The Committee suggests that it be used only when necessary for decision-making and when evidence to support its use is available."

Response: The primary benefits estimates are derived from epidemiology studies examining two large population cohorts: the American Cancer Society cohort (Pope et al., 2002) and the Harvard Six Cities cohort (Laden et al., 2006). These are logical choices because both studies are well designed and peer reviewed. In addition, EPA estimated the range of benefits derived from an expert elicitation to characterize the uncertainty in the concentration-response function for premature mortality (Roman et al., 2008). In general, benefits estimates derived from the expert elicitation functions fall between results using the epidemiology studies.

Commenter Name: Bill Perdue
Commenter Affiliation: American Home Furnishings Alliance
Document Control Number: EPA-HQ-OAR-2002-0058-2692.1
Comment Excerpt Number: 5

Comment: The wood furniture manufacturing industry is especially vulnerable to shifting domestic production to overseas sources. Wood furniture manufacturing has experienced a sustained downturn described by the U.S. Department of Commerce as a “perfect storm” of negative factors related to the housing market, foreign dumping, and a host of new standards (flammability, formaldehyde, finishing material composition, and now the proposed new Boiler MACT rule). Domestic employment in our industry has contracted from 620,000 jobs in 1990 to an estimated 360,000 jobs today, while there has been a 519% increase in wood case goods furniture imports between 1998 and 2007. Between 2000 and 2008 270 domestic furniture manufacturing operations have closed, including 112 plants in North Carolina, 31 plants in

Virginia, and 30 plants in Mississippi. Although U.S. manufacturers in the past maintained near 100% production in the United States, most major manufacturers have now relocated major portions of their manufacturing operations to overseas locations such as China and Viet Nam. The overseas infrastructure is in place to easily incorporate additional wood furniture manufacturing, and economic pressure favors a shift from domestic to overseas employment. The proposed rule will represent a tipping point for remaining domestic manufacturers, and if implemented in this form we expect to lose a very sizeable fraction of remaining domestic production.
Fortunately there is light at the end of the tunnel for those manufacturers who have maintained domestic production, or who have at the very least mothballed rather than disassemble their domestic facilities. The Center for Industrial Studies projects moderate growth of the U.S. furniture industry in 2010, and Furniture Today reports that Industry analyst Jerry Epperson of Mann, Armistead & Epperson is forecasting that U.S. consumer spending on furniture and bedding will rise 3.7% in 2010 and another 7.1% in 2011. Some domestic manufacturers have reported plans to expand domestic production for the first time in several years, however they are waiting to see the outcome of influencing activities such as the proposed boiler rule before committing to the investment in domestic production.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2601
Comment Excerpt Number: 3

Commenter Name: Ron Lindsey
Commenter Affiliation: Packaging Corporation of America
Document Control Number: EPA-HQ-OAR-2002-0058-3158
Comment Excerpt Number: 7

Comment: Our company wants to modernize and become more energy efficient and less dependent on fossil fuels, especially foreign oil. Proposals like this chew up all the available capital so you end up with costly new controls on old boilers, instead of allowing gradual movement forward with new, efficient boiler technology. The best estimates now of the capital required for the proposed rule is $30 million just for our Valdosta Mill– that’s two to three times our annual capital & maintenance budget for the entire plant!

Response:
See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2418.1
Comment Excerpt Number: 4

Commenter Name: Paul J. Allen

Commenter Affiliation: Constellation Energy
Document Control Number: EPA-HQ-OAR-2002-0058-3164
Comment Excerpt Number: 7

Comment: Requiring existing boilers to retrofit Hg and HCI control technologies, (such as activated carbon injection, carbon beds, or wet scrubbers) and CO control technology, (such as afterburners or catalytic oxidizers) to meet the proposed standards is a burden on these 20 to 25 year old power plants which may lead to the unintended consequences of shutdowns with the perverse result of higher long term emissions. These controls would be expensive, provide very small reductions, and would not likely be cost-effective. Also, note that these power facilities have Power Purchase Agreements (PPM) with the local utility and thus cannot pass on any of these emission control costs to the rate payers. Additionally, they have a very limited amount of profit margin. Therefore, the standards could likely cause the plants to shutdown. In northern California that would be a major issue, since this type of renewable energy plant replaces open burning of biomass. Furthermore, the shutdown of green power plants would lead to replacement with fossil fuel power plants, increasing emissions and diverging from the conservation, recycle, and renewable approach of the current administration and public attitude.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2601
Comment Excerpt Number: 3

Commenter Name: Steven W. Koehn
Commenter Affiliation: National Association of State Foresters
Document Control Number: EPA-HQ-OAR-2002-0058-2860.1
Comment Excerpt Number: 9

Comment: These rules surpass the emission regulations for European boilers and will require additional investments in emissions controls and fuel testing. This may discourage additional use of woody biomass energy by the forest products sector which increases their costs and reduces their competitiveness in international markets. Such impacts will result in economic impacts throughout the value chain related to the forest products industry.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2601
Comment Excerpt Number: 3

Commenter Name: W. Phillip Reese
Commenter Affiliation: California Biomass Energy Alliance
Document Control Number: EPA-HQ-OAR-2002-0058-2774.1

Comment Excerpt Number: 9

Comment: Based on data available, CBEA believes that the majority of the California biomass plants would be under CISWI or Major MACT sources, subject to the Boiler MACT rule and limitations on the set of five HAPs. Unlike the regulated utilities (Investor-Owned) and publicly-owned utilities (Municipal Utilities and Irrigation Districts, for example), which have the authority to recover costs from the electric ratepayers, the biomass power generation plants which sell power wholesale to these entities operate under set-price long-term contracts that provide absolutely no mechanism for recovery of costs that would be incurred by addition of new emission-control equipment. Therefore, even if added equipment could produce compliant emission levels, such equipment cannot be afforded by the biomass industry, leaving no other alternatives to
shutdown.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2601
Comment Excerpt Number: 3

Commenter Name: David P. Tenny
Commenter Affiliation: National Alliance of Forest Owners
Document Control Number: EPA-HQ-OAR-2002-0058-2750.1
Comment Excerpt Number: 10

Comment: As reported by an AF&PA analysis, the forest products industry estimates the cost of compliance with the emissions limitations for biomass boilers would be $3.3 billion in that sector alone. In the preamble to the proposed rule, EPA recognizes that economic burden may justify an alternative compliance method. Because the costs to industry to achieve the proposed rule's very low emissions limitations would be incredibly high and could not be consistently achieved in practice, EPA should revise its approach for biomass boilers to ensure that these boilers are not penalized because they start with a cleaner fuel.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2601
Comment Excerpt Number: 3

Commenter Name: W. Phillip Reese
Commenter Affiliation: California Biomass Energy Alliance
Document Control Number: EPA-HQ-OAR-2002-0058-2774.1
Comment Excerpt Number: 10

Comment: This proposed Boiler MACT regulation is calling for a biomass plant emission standards for the suite of five HAPS, or for CO (in the case of the few plants in California that may be "Area sources,") is unmanageable. Such a limitation would have devastating impacts on the biomass industry. The technology incorporated in converting unmarketable wood material into renewable energy does not currently lend itself to any known retrofits or modifications that would allow for such standards to be achieved. All of the California biomass power plants are currently regulated by the Air Pollution Control District or Air Quality Management District of jurisdiction, and all the biomass plants utilize Best Available Control Technology (BACT) for emission control, under California's typically strict air quality regulatory structure. To the extent that EPA continues on its course to drastically reduce the permitted levels of HAPS allowed, biomass plants will be shuttered. Agricultural residue burning will increase in the Sacramento, San Joaquin, Coachella and Imperial Valleys and during in-forest thinning operations throughout the State. Workers will be unemployed. Ultimately, green jobs will be lost and California's air quality will degrade.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2601
Comment Excerpt Number: 3

Commenter Name: Robert R. Perry
Commenter Affiliation: FirstEnergy Generation Corp
Document Control Number: EPA-HQ-OAR-2002-0058-2772.1
Comment Excerpt Number: 10

Comment: This issue is germane to FGCO as we are presently involved in repowering our R. E Burger Plant to burn biomass. Simply put the economics will determine the feasibility of any biomass repowering project. However, EPA has proposed ICI Boiler MACT emission limits for new or reconstructed biomass units without any economic analysis of the potential impacts on future biomass repowering efforts, including the R.E. Burger Plant biomass project. Given the growing public policy encouraging biomass and other renewables to increase our nation's energy independence, EPA should conduct an evaluation of the economic impacts of the Proposed Rule on future efforts to repower with renewable biomass fuels.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2418.1
Comment Excerpt Number: 4

Commenter Name: Jennifer Klein
Commenter Affiliation: Ohio Chamber of Commerce

Document Control Number: EPA-HQ-OAR-2002-0058-2901.1
Comment Excerpt Number: 11

Comment: The proposed revised standards would seriously impede the ability of Ohio businesses to remain economically competitive. Air quality in Ohio has and will continue to improve as a result of numerous programs and regulations that have already been placed upon the business community. The Chamber believes EPA has significant discretion in the Boiler MACT program to protect public health while avoiding the unnecessary burdens these proposed rules will impose.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2601
Comment Excerpt Number: 3

Commenter Name: Catherine W. McCuthen
Commenter Affiliation: Blue Heron Paper Company
Document Control Number: EPA-HQ-OAR-2002-0058-2892.1
Comment Excerpt Number: 13

Comment: Our industry sector has been savaged by the economy and the volatility of fossil fuel prices. It is simply not an option to convert to exclusively natural gas as a fuel so as to maintain a bearable level of regulation. Biomass is a low-HAP fuel and should not be unduly penalized through the NESHAP process. Doing so will result in plant closures, unemployment and further flight of manufacturing operations overseas where the level of regulation is substantially lower. EPA must bring a dose of reality to the table and recognize that the impact of its rules will be increased HAP emissions through additional uncontrolled combustion of biomass and decreased domestic employment. Congress never intended such draconian effects from the NESHAP program.

Response:
See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2601
Comment Excerpt Number: 3

Commenter Name: Allyn Ford
Commenter Affiliation: Roseburg Forest Products
Document Control Number: EPA-HQ-OAR-2002-0058-3163
Comment Excerpt Number: 13

Comment: This rule, as proposed, will cause serious economic damage to Roseburg Forest Products facilities in several states:

Existing Units:

As mentioned earlier, Roseburg Forest Products (RFP) owns and operates wood products facilities in several states. RFP has analyzed the financial impact this rule will impose on its biomass units as a result of this rule; in order to ensure that its estimated costs are realistic, RFP requested a third party to assist in this determination. This analysis has revealed that RFP will be subject to over $48.5 million in capital expenditures for additional control equipment, with additional annual operating costs of over $6.2 million.

To put this in a clearer, more complete perspective, RFP's capital expenditure for just its biomass boilers and their respective annual operating costs borne in each state includes:

California (1 unit):

Capital costs: $3.9 million

Annual operating costs: $500,000

Oregon (6 units):

Capital costs: $36 million

Annual operating costs: $4.7 million

Georgia (1 unit):

Capital costs: $3.7 million

Annual operating costs: $450,000

South Carolina (1 unit):

Capital costs: $4.9 million

Annual operating costs: $576,000.00

When compared to RFP's annual payroll amount of $140.5 million to employ 3,700 people, $48.5 million in additional capital costs with an ongoing annual operation cost of $6.2 million is staggering. Imposing standards as strict and expensive as this on an industry utilizing clean, green energy sources in order to obtain a negligible decrease in emissions will seriously impact our ability to produce product and provide jobs.

New Unit:

In addition to the excessive costs associated with existing units, RFP has determined costs associated with a specific unit that would be considered a "new unit" under the proposed rule. RFP has seriously considered replacing an existing unit with a new unit that would be capable of producing green, biomass-generated electricity according to the Administration's stated goal. After spending quite some time researching what would be required of this specific new biomass unit, we find the costs of complying with the proposed rule shocking.

In order to comply with this rule, a new boiler would need to install:

An ESP $3.19 million
HCI Control injection and
Activated Carbon injection at $1.01 million
CO Catalyst at $0.62 million
NOx Catalyst (NSR req'd) $1.35 million
For a total of $6.17 million

Annual operating costs associated with this proposed new boiler are steep:

1. To meet the proposed rule's mercury standard, the boiler's emissions would need to be reduced by 0.0028 lb/hr. Removing this amount of mercury will require injecting activated carbon at a rate of 50 lb/hr. At the current purchase price (not including transportation costs) the annual cost of activated carbon will be $438,000.00 to remove 23 pounds of mercury.

2. Meeting the proposed rule's HCI standard will require injecting sodium bicarbonate at a rate of 110 lb/hr in order to remove 18 lb/hr of HCI (which originates as salt that has been taken up by the tree). This results in an annual sodium bicarbonate usage of 963,600 pounds, for a total annual purchase price (not including transportation) of $79,500.

A possible alternative for HCI would be to install a wet scrubber at the end of the stack. Not considering what the water quality/permitting implications would be, a system for this boiler would evaporate 77 gallons of water per minute; 4,620 gallons per hour; or 36,960,000 gallons per year. Probably not a good option for our thirsty world.

3. Both of these injection systems obviously place an enormous additional load on the ESP, requiring that it be sized large enough to accommodate the massive load of particulate headed its way from upstream pollution control devices.

4. In addition, CO catalyst is known to have a short life expectancy, needing to be replaced at least every 1 to 2 years. The cost associated with this replacement is $320,000.00.

5. The incremental cost of energy needed to operate all this pollution control equipment is anticipated result in a significant increase over current costs.

6. Finally, where will all this pollution control waste go? Ultimately, it will be placed in a landfill at a cost of approximately $30 per ton or $21,000 per year.

As you can see from the well researched example above, the capital and operating costs on a single unit will be significant. As a result, fewer investments will be made in biomass power generation.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2418.1
Comment Excerpt Number: 4

Commenter Name: Mick Baranko
Commenter Affiliation: Douglas County Forest Products
Document Control Number: EPA-HQ-OAR-2002-0058-2856.1
Comment Excerpt Number: 15

Comment: Our industry sector has been savaged by the economy and the volatility of fossil fuel prices. It is simply not an option to convert to exclusively natural gas as a fuel so as to maintain a bearable level of regulation. Biomass is a low-HAP fuel and should not be unduly penalized through the NESHAP process. Doing so will result in plant closures, unemployment and further flight of manufacturing operations overseas where the level of regulation is substantially lower. EPA must bring a dose of reality to the table and recognize that the impact of its rules will be increased HAP emissions through additional uncontrolled combustion of biomass and decreased domestic employment. Congress never intended such draconian effects from the NESHAP program.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2601
Comment Excerpt Number: 3

Commenter Name: Michael Hutcheson
Commenter Affiliation: Ameren Services
Document Control Number: EPA-HQ-OAR-2002-0058-2803.1
Comment Excerpt Number: 31

Comment: The use of the Morgenstern et al. (2002) methodology and assumptions to estimate the effect of the proposed rule on employment is improper. The Morgenstern methodology is based on general data in four large industrial sectors during a 12 year period (1979 to 1991) which includes 1990 the date of the Clean Air Act Amendments. Morgenstern's methodology does not identify the direct effects of environmental regulation on employment, it measures the effect of reported environmental expenditures on employment at a time when environmental regulation was in it's infancy. The period studied cannot be considered analogous to this proposed regulation for the following reasons:

During the early years of environmental regulation and the associated environmental expenditures studied, control costs were on the order of $500 per ton of pollutant abated. Today proposed rule has costs of $27,000 per ton of PM abated for existing biomass fuel fired sources, $40,000 per ton of PM for liquid fuel fired sources and $95,000 per ton of pm for coal units.

Environmental regulations in the early days and those costs were directly related to production processes and increases in costs affected all producers in an industry similarly. These proposed regulations affect utility (steam) costs and are not directly attributable to any production process. Costs for compliance will vary greatly across individual industries with little chance for pollution abatement activities or byproduct developments to lessen the costs.

The proposed regulations will eliminate several currently utilized byproduct reutilization programs such as coal fly ash reutilization in concrete because the activated carbon required to control Hg and/or dioxin/furans renders fly ash unsuitable for use in concrete mixes.

The costs for compliance will require much larger capital investments than the process specific regulations which were studied by Morgenstern et al. (2002). The capital investments required under this proposed rule will require financing which may not have been required for the much smaller capital investment required during the period studied by Morgenstern.

Morgenstern studied general cost and employment data in four specific large industries affected by environmental regulation. This regulation affects both large and small industries as well as commercial and institutional entities. These later two affected entities are not subject to the "demand effect" described by Morgenstern because they are not involved in production. Similarly, their operations cannot be subject to a "factor-shift effect" because there are not involved in production and therefore, post regulation production technologies will not have the same impact on employment as in industry. Unlike a production facility complying with environmental regulation of production processes, commercial and institutional entities with boilers affected by the Boiler MACT will not be able to substitute labor for other production inputs as production choices become more flexible over

time as US EPA (and Morgenstern) indicates results in positive job gains. These entities cannot substitute labor for other production inputs because the Boiler MACT affects utility costs and steam production not production costs.

In the years studied by Morgenstern, the United States was a leading industrial nation and under little economic pressure to compete internationally for industrial jobs. However, the advances in the international shipping industry which occurred beginning in the late 1980s and continuing through the present have resulted in international competition for industrial jobs. The US must compete with lower labor costs, lower tax rates and lower environmental costs in other countries competing for industrial jobs. The proposed regulation on industrial, commercial and institutional boilers, puts additional cost pressures on US industries not incurred in other industrializing nations who are competing for the industrial jobs which are jeopardized by the proposed rule.

Morgenstern's methodology assumed large plants bear most of the regulatory costs and this assumption may have been proper for large industries like the pulp and paper, plastics, petroleum and iron and steel industries studied by Morgenstern. This assumption is not transferrable to the Boiler MACT which requires compliance for all affected units and therefore affects large and small industries as well as large and small commercial and institutional entities.

For the above reasons, the Morgenstern et al. analysis is not analogous to the Boiler MACT. All of the above indicates that the economic impact analysis and the regulatory impact analysis conducted for this proposed rule underestimates costs, overestimates benefits and underestimates job losses and as result should be revised with a more reasoned analysis.

Response: The principal argument of the comment is that the data used in the 2001 study, which covered the petroleum, pulp and paper, plastics, and iron and steel industries over the period 1979-91, are not relevant to the proposed boiler MACT. The commenter asserts that the effects found, even if transferrable to the boiler MACT industries, were based on average abatement costs of $500/ton whereas the new regs involve costs as much as two orders of magnitude higher. Further, he argues that 'environmental regulations in the early days and those costs were directly related to production processes and increases in costs affected all produces in an industry similarly.'

While it is true that the costs in this rule are much higher than the ones considered in the study, and there is certainly a possibility of nonlinearities in the employment effects, no evidence of such nonlinearlties is offered. As for the assertion that the cost increases affected all producers in an industry similarly,it is doubtful that this is the case. The plant-specific Census data used demonstrated a remarkable amount of heterogeneity of cost impacts associated with the observed environmental expenditures.

The claim that the industry is starkly different from the four industries studied is not supported. On average the study found an (insignificant) gain of 1.5 jobs per $1 million in added environmental spending. In two capital-intensive industries studied, plastics and petroleum, there were small but significantly positive employment effects which were linked to (pro labor) factor shifts and relatively inelastic estimated demand. Several of the industries studied are covered by the boiler MACT. The fact that advances in international shipping put greater cost pressure on US industry may be true, but it is not clear how large an effect that would have.

Commenter Name: David M. Kiser
Commenter Affiliation: International Paper Company
Document Control Number: EPA-HQ-OAR-2002-0058-2777.1
Comment Excerpt Number: 33

Comment: These high costs coupled with adverse environmental detriment will also have a negative consequence on jobs and the economy as well, as few if any businesses would find it possible to comply with such an absurd requirement. In order to avoid this consequence, the proposed rule(s) need to be substantially modified.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-3193
Comment Excerpt Number: 1

Commenter Name: Christopher S. Colman
Commenter Affiliation: Hovensa LLC
Document Control Number: EPA-HQ-OAR-2002-0058-2863.1
Comment Excerpt Number: 34

Comment: Because of the need to dynamically adjust the fuel balance in the refinery and to remain in operation when fuel gas producing units are offline or running at reduced rates, a remote facility must have the capability to burn oil in many of the units at the facility. Similarly, because of the need for spare capacity and redundancy, there are more units to maintain operations, often of a smaller size. The effect is that Boiler MACT will have a disproportionate effect on these remote oil fired facilities. For example, HOVENSA has 23 dual fuel heaters and boilers burning residual fuel.
It should also be noted that these add-on controls will consume power and utilities which must be generated by HOVENSA from additional fuel burning. The increased emissions from the utility demand will, in this case, offset perceived gains from the emissions controls required under Boiler MACT. The magnitude of these power and utility demands might also require the affected remote facility to install additional utility systems (including combustion units), increasing the overall cost of compliance and add more air emissions.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-2418.1
Comment Excerpt Number: 4

Commenter Name: Brad James
Commenter Affiliation: Trinity Consultants
Document Control Number: EPA-HQ-OAR-2002-0058-2853.1
Comment Excerpt Number: 40

Comment: Due to all the reasons highlighted above and in many other comments to this rule, EPA has proposed rules that violate section 112 of the CAA, are far more stringent than necessary, and are completely unworkable even for the industry leaders. The costs of implementing the proposal greatly outweigh any potential benefits. If put into effect, EPA's proposal would deal another hard blow to the already struggling economy and force some companies to shut their doors. This is not what Congress had in mind when it required MACT Floors to be set at a level "achieved in practice." 42 U.S.C. § 7412(d)(3).

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-3193
Comment Excerpt Number: 1

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 127

Comment: The bulk of the capital investment will be skewed toward the initial year. Industry incurs those costs in real time and they may be high enough that it could trigger a decision to pull out of the US market, thus costing jobs. Raising the cost of capital will also impact future investment and job growth in high paying manufacturing jobs further slowing the economic recovery of the manufacturing sector.

Response: See answer for
Document Control Number: EPA-HQ-OAR-2002-0058-3193
Comment Excerpt Number: 1

Commenter Name: Wayne Brandt
Commenter Affiliation: Minnesota Forest Industries
Document Control Number: EPA-HQ-OAR-2002-0058-3220
Comment Excerpt Number: 1

Comment: Forest products is one of the leading industrial sectors in Minnesota, generating over $8.6 billion in revenue and providing more than 36,000 jobs. AF&PA estimates that the proposed Boiler MACT rule will cost the forest products industry in Minnesota more than $160 million at a time when our companies are working hard to emerge from the deepest recession in our nation since the Great Depression. The estimated cost for all affected boilers in Minnesota is $730 million, including other industrial sectors as well as commercial and government facilities. In light of the huge cost impacts, it is imperative that the boiler MACT rule be legally and technically sound, and not result in costs that are unnecessary to protect public health and the environment. We believe that the proposed rule falls far short of this standard.

Response: EPA acknowledges the comments. The costs of the rule have been decreased through changes to subcategories, emission limits (based on new data, data corrections, and the MACT floor methodology discussed in the preamble to the final rule).

Commenter Name: Michael A. Livermore
Commenter Affiliation: Institute for Policy Integrity, New York University School of Law
Document Control Number: EPA-HQ-OAR-2002-0058-2720.1
Comment Excerpt Number: 17

Comment: Estimates of employment impact derived from Morgenstern et al.: The Regulatory Impact Analysis uses two techniques to estimate the changes in employment due to the proposed rules. The first is a longstanding method used by EPA in many previous analyses. This technique looks at the output decrease in the relevant sectors and uses an estimate for jobs per unit of output to calculate a projected decrease in employment. This "demand effect" technique for projecting changes in employment is described in the Economic Analysis Resource Document issued by the Office of Air Quality Planning and Standards in April of 1999. [Footnote: OFFICE OF AIR QUALITY PLANNING AND STANDARDS, EPA, OAQPS ECONOMIC ANALYSIS RESOURCE DOCUMENT at 5-42 to 5-43 (1999).] It contains an implicit assumption that the result of environmental regulations will be price increases and that these price increases will result in lower sales for regulated entities.

However, this type of employment projection is incomplete. The agency correctly identifies that there are at least two types of employment effects from environmental regulations which are not included in the "demand effect" calculation: the "cost effect" and the "factor shift effect." [Footnote: RIA at 4-6 to 4-7.] The "cost effect" recognizes that, for a given level of output, expenditures on reducing pollution often require additional employees. The "factor shift effect" recognizes that production can be more or less labor intensive after compliance with an environmental regulation.

The size of each of these effects and the direction of the "factor shift effect" are all empirical matters and will likely vary from industry to industry and from regulation to regulation. In order to estimate these effects, EPA uses econometric estimates from a 2002 paper by Morgenstern et al. [Footnote: RIA at 4-7.] This paper estimated the employment effects of spending on environmental policies across a number of industries. [Footnote: Richard D. Morgenstern, William A. Pizer & Jhih-Shyang Shih, Jobs Versus the Environment: An Industry Level Perspective, 43 JOURNAL OF ENVIRONMENTAL ECONOMICS AND MANAGEMENT 412, 412 (2002).] As the RIA recognizes, the point estimates do not perfectly correspond to the analysis that EPA is doing. The range of industries analyzed is not the same and the paper uses older data.

Nevertheless, this technique at least recognizes and has the possibility of capturing effects that the traditional techniques of estimating employment effects cannot. This makes the estimates derived from the Morgenstern paper at least as valuable as the traditional techniques of estimating employment effects. The adoption of this technique by EPA could attract additional interest in this area and encourage economists to publish new studies on the topic with newer data.

Response: EPA acknowledges the comments. The costs of the rule have been decreased through changes to subcategories, emission limits (based on new data, data corrections, and the MACT floor methodology discussed in the preamble to the final rule).

Emission Impacts

Commenter Name: Michael L. Steele
Commenter Affiliation: CraftMaster Manufacturing, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-1907.1
Comment Excerpt Number: 23

Comment: Switching from Coal to Biomass, Preamble IV D

What is the basis for stating that switching from coal to biomass would result in similar impacts on HAP's emissions? What organic HAP's would increase and why would lower non-Hg metallic HAP's not compensate for any increase?

Response: This statement was referring to aggregate emissions, and there was no attempt to compare individual pollutant emissions between coal and biomass. The CO emission factors for biomass are higher than coal for the stoker and FB subcategories and so overall emissions would be higher.

Commenter Name: Richard T. Metcalf
Commenter Affiliation: Louisiana Mid-Continent Oil and Gas Association
Document Control Number: EPA-HQ-OAR-2002-0058-2699.1
Comment Excerpt Number: 4

Comment: For refinery process heaters and boilers, the best performers are those where, for safety reasons, excess air levels are set somewhat above the excess air level that provides optimized energy efficiency. Typical tuning guidelines suggest an upper CO level of 400 ppmv. Fully consider the increase in NOx, SO2, VOC and PM and the potential loss in boiler and process heater energy efficiency that result from forcing an excessively low CO emission.

Response: See the response to comment EPA-HQ-OAR-2002-0058-2960.1, excerpt 124.

Commenter Name: Robert R. Scott

Commenter Affiliation: New Hampshire Department of Environmental Services, Air Resources Division
Document Control Number: EPA-HQ-OAR-2002-0058-2734.1
Comment Excerpt Number: 4

Comment: Balancing CO reductions with nitrogen oxide (NOx) reductions already in place in ozone non-attainment areas
Many states that have been designated non-attainment for ozone, including New Hampshire, have worked diligently over the past 15 years to reduce ozone through the reduction of NOx emissions. Since forcing down CO emissions can result in increases in NOx emissions from fuel burning devices, this current effort to control organic HAPs through reductions in CO may negate the efforts conducted by states to improve ozone levels. NHDES encourages EPA to balance CO and NOx emission levels to achieve optimum boiler efficiency as well as minimize the impact on state's efforts to reduce ozone.

Response: See the response to comment EPA-HQ-OAR-2002-0058-2697.1, excerpt 2.

Commenter Name: Jay C. Moon
Commenter Affiliation: Mississippi Manufacturers Association
Document Control Number: EPA-HQ-OAR-2002-0058-2690
Comment Excerpt Number: 7

Comment: EPA's focus on individual HAPs has resulted in a failure to recognize the critical interplay between emissions controls and emissions of other pollutants. For example, we are concerned that the controls necessary to meet the stringent emissions limitations for CO will result in increased energy usage, with the concomitant increase in emissions of NOx and other pollutants. Further, EPA failed to account for this interrelationship in its economic analysis.

Response: See the Preamble for response. The CO limits in the final rule have been revised to higher limits, and as such the use of CO oxidation catalyst controls will be limited. Limited use of CO controls will mitigate the emissions impact from their use and so was not considered in the analysis.

Commenter Name: Arthur N. Marin
Commenter Affiliation: NESCAUM
Document Control Number: EPA-HQ-OAR-2002-0058-2893.1
Comment Excerpt Number: 12

Comment: Many NESCAUM states have adopted, or are in the process of adopting, standards for ultra-low sulfur heating oil; it is imperative that EPA's proposed regulations do not impair state efforts to reduce sulfur emissions from these sources. NESCAUM recommends that EPA analyze the multi-pollutant benefits gained by encouraging the use of 15 ppm ultra-low sulfur heating oil and incorporate these requirements, when appropriate, in the final rule. NESCAUM recommends that EPA, at a minimum, create two additional categories of boilers: one for units smaller than 1 mmBtu/hr and another for “limited use” boilers.

Response: The EPA thanks the commenter for their input, but there was not enough emissions data from specific facilities to consider ultra-low sulfur oil as a separate subcategory. If data is provided this topic may be revisited in the future. The commenter had provided only general emission factors for different fuel types which are not considered in this analysis.
The EPA agrees with the commenter about limited used boilers, and a separate limited use subcategory for units operating less than 876 hours has been implemented; see the Preamble for a full response. The EPA has not incorporated a deminimus size threshold into the rule, but expects that many of the extraordinarily small units will meet the definition of a hot water heater. Further, the only requirement for small units is a tune-up and the tune-up is expected to be a relatively simple exercise, for small units this exercise is similar to tuning a home furnace.

Commenter Name: Arnold Schwarzenegger
Commenter Affiliation: Governor Arnold Schwarzenegger
Document Control Number: EPA-HQ-OAR-2002-0058-2697.1
Comment Excerpt Number: 2

Comment: In California, Biomass to Energy (BTE) boilers are tuned to reduce oxides of nitrogen (NOx) emissions at the expense of some increased carbon monoxide (CO) emissions (an attainment pollutant) because of California’s ozone nonattainment problem. Modifying a biomass boiler to meet the CO emissions requirements used as a surrogate for non-dioxin organic hazardous air pollutants (HAP) will result in higher emissions of NOx that may trigger New Source Review (NSR) requirements for best available control technology and offsets. ARB believes U.S. EPA needs to re-evaluate the increased NOx emissions of this proposed standard and the impacts on states, such as California, in meeting the National Ambient Air Quality Standards for ozone.

Response: See the Preamble for response on how we addressed and revised CO limits.

Commenter Name: Henry T. Graham
Commenter Affiliation: Louisiana Chemical Association
Document Control Number: EPA-HQ-OAR-2002-0058-2731.1
Comment Excerpt Number: 4

Comment: Fully consider the increase in NOx, SO2, VOC and PM and the potential loss in boiler and process heater energy efficiency that result from forcing an excessively low CO emission.

Response: See the response to comment EPA-HQ-OAR-2002-0058-2960.1, excerpt 124.

Commenter Name: Arnold Schwarzenegger
Commenter Affiliation: Governor Arnold Schwarzenegger
Document Control Number: EPA-HQ-OAR-2002-0058-2697.1
Comment Excerpt Number: 5

Comment: BTE facilities required to install an oxidation catalyst to meet the proposed CO emission limit may have space limitations or other engineering constraints which would prevent the installation of the additional control equipment. For example, the temperature regimes at the catalyst placement site may not be high enough for the catalyst to function properly. In this case, additional heat (by co-firing) will be needed to get the exhaust temperature within the required temperature range. This co-firing will result in an increase of NOx and other pollutants and may also trigger NSR in California. ARB recommends U.S. EPA perform a more thorough analysis on the feasibility of existing facilities to meet the proposed standards.

Response: See the response to comment EPA-HQ-OAR-2002-0058-2690, excerpt 7 regarding emission increases from CO controls and the response to comment EPA-HQ-OAR-2002-0058-2697.1, excerpt 2 regarding NSR.

Commenter Name: Robert E. McKenna
Commenter Affiliation: Motor and Equipment Manufacturers Association
Document Control Number: EPA-HQ-OAR-2002-0058-2778.1
Comment Excerpt Number: 7

Comment: EPA's focus on individual HAPs has resulted in a failure to recognize the critical interplay between emissions controls and emissions of other pollutants. For example, we are concerned that the controls necessary to meet the stringent emissions limitations for CO will result in increased energy usage, with the concomitant increase in emissions of NOx and other pollutants. Further, EPA failed to account for this interrelationship in its economic analysis.

Response: See the response to comment EPA-HQ-OAR-2002-0058-2690, excerpt 7.

Commenter Name: Chris Greissing
Commenter Affiliation: Industrial Minerals Association
Document Control Number: EPA-HQ-OAR-2002-0058-2740.2
Comment Excerpt Number: 9

Comment: This variation will be especially true for low nitrogen oxide ("NOx") boilers which can generate more CO even when operating at maximum efficiency. These boilers may not be able to meet the MACT limits for CO because in order to reduce NOx emissions they operate at a lower temperature and inherently result in more incomplete combustion. Failure to recognize this fact creates a tension between controlling NOx emissions and controlling CO emissions, and likely would result in increases in NOx emissions. EPA should take into account that achievement of lower NOx emissions increases CO emissions in identifying which boilers are the best performers. CO standards should be sufficiently flexible to accommodate the effects of low-NOx boilers. In the alternative, boilers equipped with low-NOx burners could be classified into a separate subcategory.

Response: See the Preamble for discussion of the relationship between CO and NOx. The EPA has not included a separate subcategory for low-NOx boilers, see the response to comment EPA-HQ-OAR-2002-0058-2916, excerpt 2.

Commenter Name: Donald R. Schregardus
Commenter Affiliation: Department of Defense
Document Control Number: EPA-HQ-OAR-2002-0058-2763.1
Comment Excerpt Number: 11

Comment: In the cost benefit analysis, EPA failed to consider the detrimental effects of increased criteria pollutants (in particular, nitrogen oxides (NOx)) as a direct result of employing combustion control technologies for the control of CO.

Extensive data from the boiler community and EPA shows that reductions in combustion-related CO are accompanied by increases in emission levels of NOx. However, EPA states in the preamble at page 32048 that the rule will result in substantial reductions of NOx and all criteria pollutants. Many boilers in the solid fuel subcategories are located in either former or current ozone non-attainment areas and are permitted with strict NOx limitations through various regulatory mechanisms such as New Source Performance Standards or New Source Review to ensure the NOx emissions do not adversely impact State efforts to attain the National Ambient Air Quality Standards (NAAQS). Elevated NOx emission levels that result from the installation of CO controls can place a source at risk of potential violations of existing permit limits. When establishing CO emission standards, EPA should ensure the limits are achievable and do not result in an increase in NOx emissions that violate applicable limits or hinder State efforts to attain or maintain compliance with the NAAQS.

EPA should reevaluate each source used to establish the CO MACT floor to determine the impact on NOx emission levels, permitted NOx levels, and installed NOx controls that will result from limits placed on O emissions.

Response: See the response to comment EPA-HQ-OAR-2002-0058-2697.1, excerpt 2.

Commenter Name: Melvin E. Keener
Commenter Affiliation: Coalition for Responsible Waste Incineration (CRWI)
Document Control Number: EPA-HQ-OAR-2002-0058-2824.1
Comment Excerpt Number: 19

Comment: CRWI believes that EPA is overestimating the degree of reductions SO2 that will be achieved by HCI control.

As EPA knows, HCI absorbs readily in water at most pH's. As a result, most wet scrubbers designed to control HCI operate at acidic pH's. On the other hand, SO2scrubbing requires pH's above 8.5 (alkaline). Operating controls for an alkaline scrubber are much more difficult due to the formation of carbonates in the process. This can lead to plugging and more frequent cleaning. For this reason, facilities that wish to control HCI will operate their scrubber at acidic pH's because it will achieve the same results with fewer maintenance problems. Consequently, technology to control HCI will not necessarily control SO2.

Response: No data was available to distinguish between acidic vs alkaline wet scrubbers and their potential effect on emission reduction calculations. Based on available information it is shown that both HCl and SO2 are reduced in proportionate amounts. If a boiler needs to reduce its HCl by 50% to meet the MACT floor, then this same 50% reduction is used for SO2 emission reduction calculations; however, scrubbers are shown to remove 95-99% SO2 and thus the calculations would be low if a scrubber is operated at full efficiency.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 124

Comment: Another potential consequence of increasing excess O2 to minimize CO is increased NOx emissions. Typically, NOx emissions decrease with decreasing excess O2 over the normal operating range (Relationship Figure below, left). Thus, tuning to optimize efficiency also is consistent with low NOx emissions. [Footnote: EPA, 1983. Combustion Efficiency Optimization Manual for Operators of Oil- and Gas-Fired Boilers. EPA-340/1-83-023, Stationary Source Compliance Division, Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Washington, D.C.] Raising the excess O2 level to minimize CO would have exactly the opposite effect on NOx.

Single-digit CO levels are likely to be difficult to achieve in many boilers and process heaters via the combustion system. The design, operating and condition characteristics of boilers and process that influence CO emissions vary widely among different units, even within the same design category. While reducing CO to optimal levels is beneficial with respect to energy efficiency and emissions of HAPs, NOx, and greenhouse gases, reducing CO below this level is likely to drive these factors in the opposite direction.

Each boiler or process heater will have its own unique signature profiles of NOx, CO and smoke versus excess O2 because of the design and condition of the unit, burner design characteristics, air in-leakage, the distribution of air-fuel ratios among individual burners in a multi-burner unit, the level and variability of process operation, the type and composition of the fuel fired, ambient conditions and other factors. It is not unusual to find two boilers at the same facility of identical design, fuels and vintage, but with different operating characteristics. Thus, just as it is not possible to recommend a single target excess O2 level for all units, it is not possible to predict what minimum CO level all boilers and process heaters can achieve. Operating a unit at a condition which minimizes CO will almost certainly not be the optimum condition for low NOx emissions and high thermal efficiency. Operating at excess O2 levels higher than the optimum operating range will increase energy consumption and consequently increase emissions of CO_2 and NOx, and offset any reductions in HAP emissions that may be achieved.

[See submittal for graph of typical relationships between CO, hydrocarbons, and efficiency with excess oxygen in practical combustion systems.

Recommendation: Take account of the impact of the proposal on energy efficiency and pollutant generation in determining the CO emission limit that should be imposed.

Response: See the Preamble for response on how we addressed and revised CO limits.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 146

Comment: The numerical emission limits being considered would necessitate combinations of emission controls that have adverse effects on each other. In other words, the presence of one control technology could prevent a second control technology from operating at optimum performance. As an example, a primary control for Hg emissions involves the injection of activated carbon into the flue gas. The mercury is oxidized on the active sites on the carbon particles. The oxidized form of Hg can then either be recovered by the particulate control equipment or by a scrubber (since oxidized Hg is soluble). The oxidation reactions only occur at temperatures below about 350ºF. The effectiveness of the activated carbon for oxidizing Hg is dependent upon the amount of time that the carbon has to attract the Hg to one of its active sites. The use of activated carbon injection for Hg control is negatively affected by the presence of sulfur trioxide (SO3). SO3 occupies the active sites on the carbon, taking away those sites from the Hg. Even a few parts per million of SO3 can have a significant negative impact on the Hg removal that is achieved by activated carbon injection. Small amounts of SO3 are generated as part of the combustion process for sulfur-containing fuels, even natural gas, while the bulk of the sulfur in the fuel is oxidized to SO2. However, other control devices, such as CO oxidation catalyst or SCR NOx reduction catalyst, will convert an additional percentage of the SO2 to SO3, resulting in poor Hg removal.

It is likely other negative interactions occur, but since the needed combination of technologies is undemonstrated all of those concerns cannot be anticipated or discussed.

Recommendation: Only impose numerical emission limits where the combination of necessary controls is demonstrated and fully evaluated.

Response: See the response to comment EPA-HQ-OAR-2002-0058-2702.1, excerpt 214.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 170

Comment: Stack testing at maximum chloride and mercury levels will result in significant chloride and mercury emissions that would not normally occur, since most boilers and process heaters never actually run maximum chloride and mercury fuels. While the amount of unnecessary, excess chloride and mercury emissions may be relatively small for any one boiler or process heater, the national total will be significant because of the large number of boilers and process heaters subject to this requirement. The claimed mercury emission reductions for this proposal should have been reduced to account for these emissions. In fact, the Agency must show that the excess emissions generated by the testing requirement do not result in this rule increasing national chloride and mercury emissions, as it may.

Recommendation: Estimate the excess chloride and mercury emissions that result from the requirement to perform performance tests at maximum chloride and mercury levels and incorporate those emissions into the record and into the emission calculations associated with this rulemaking. Demonstrate that, considering these excess emissions, the proposal actually results in a net decrease in emissions of these pollutants on a unit by unit basis and on a national basis.

Response: The maximum chlorine and mercury (worst-case conditions) are based on fuels which would reasonably be combusted at the unit and therefore EPA expects that facilities firing “worst case” fuels would capture fuels they would use sometime in the future, instead of solely for the reason of compliance. We would expect that units will use a variety of compliance techniques including purchasing of specified fuel types with a maximum level of chlorine and mercury content in order to remain in compliance with the standard. For calculating emissions reductions the baseline values were based on prior performance testing under these same maximum chlorine and mercury criteria, so emission reduction calculations are based on worst-case conditions. EPA also notes that it is common practice to require performance testing at worst-case conditions.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 204

Comment: Claim: The Department of Energy has conducted energy assessments at selected manufacturing facilities and reports that facilities can reduce fuel/energy use by 10 to 15 percent by using best practices to increase their energy efficiency. Many best practices are considered pollution prevention because they reduce the amount of fuel combusted which results in a corresponding reduction in emissions from the fuel combustion. The most common best practice is simply tuning the boiler to the manufacturer's specification.

Comment: Major source typically have energy management systems, so experience at sites without such systems does not apply. No explanation is provided on how EPA concluded that this 10 to 15% number was translated into a nationwide reduction of 1% for major sources and we see no basis for that claim. Furthermore, the cited best practice is not applicable because the rule proposal requires tune-ups to minimize CO, not to tune to the manufacturers specifications. As discussed in our comments on the tune-up provisions, tuning to minimum CO significantly reduces energy efficiency.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3122, excerpt 25.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-2702.1
Comment Excerpt Number: 214

Comment: Additional Source Constraints
Effects of Putting Multiple Controls in Series on Units.
A.
The limits being considered for Boiler MACT would necessitate combinations of emission controls that have adverse effects on each other. In other words, the presence of one control technology could prevent a second control technology from operating at optimum performance.

A primary control for Hg emissions involves the injection of activated carbon into the flue gas. The mercury is oxidized on the active sites on the carbon particles. The oxidized form of Hg can then either be recovered by the particulate control equipment, or by the scrubber (since oxidized Hg is soluble). The oxidation reactions only occur at temperatures below about 350ºF. The effectiveness of the activated carbon for oxidizing Hg is dependent upon the amount of time that the carbon has to attract the Hg to one of its active sites.

The use of activated carbon injection for Hg control is negatively affected by the presence of sulfur trioxide (SO3). SO3 occupies the active sites on the carbon, taking away those sites from the Hg. Even a few parts per million of SO3 can have a significant negative impact on the Hg removal that is achieved by activated carbon injection. Small amounts of SO3 are generated as part of the combustion process for sulfur-containing fuels, while the bulk of the sulfur in the fuel is oxidized to SO2. However, other control devices, such as CO oxidation catalyst or SCR NOx reduction catalyst, will convert an additional percentage of the SO2 to SO3, resulting in poor Hg removal.

Response: See the Preamble for response.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-2702.1
Comment Excerpt Number: 216

Comment: There will be adverse environmental effects for those units that can use wet scrubbers. This is because there are very high water use requirements for scrubbing. Finally, EPA states that 330,000 tons of CO_2 would be reduced under rule. It is not clear where EPA obtained this data or whether the reference should have been to reductions in SO2. This would be similar to the information EPA includes in Table 14. 75 FR 32041.

Response: EPA has adjusted the subcategories to a single solid fuel group that will require less units to install add-on HCl control devices. Further, the Agency has adjusted the assumptions of the analysis to consider dry injection removal at areas that do not have wastewater discharge permits. The reference to 330,000 tons of CO_2 noted by the comment is carbon monoxide emission reductions, see 75 FR 32040. EPA has revised its estimated emission impacts in the final rule.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 253

Comment: Efforts to maximize boiler efficiency, and reduce NOx emissions, have also been accomplished by reducing excess air levels until the point where CO emissions begin to climb. Operation at excess air levels which result in CO emissions in the 100-400ppm range provides the most efficient balance between stack heat loss and lost potential energy from incomplete CO oxidation.

* Reducing CO to extremely low levels will require increased excess air levels which reduce efficiency, increasing the amount of fuel that must be fired and therefore increasing the total mass of other criteria pollutants (i.e. NOx, SO_x, PM, etc.).

In some cases boiler designs have been optimized to provide the smallest possible footprint, leaving furnace dimensions that are just large enough to provide CO burnout to reasonable levels. Thus, very low CO emissions would require a combustion chamber space heat release rate on the order of 50,000 Btu/cubic foot. Very few package boilers have this low of a space heat release rate. Most are in the range of 80,000 to 100,000 Btu/cubic foot. Additionally the design of these boilers by necessity will have some by-passing or leaks from the furnace side to the convection side causing CO quenching.

The chart shows computed NOx and CO as a function of temperature and residence time. Chart shows that for low NOx, the adiabatic temperature must be below ~3,000 deg F. Once all mixing is complete, to achieve 1ppm CO requires 0.01 seconds of additional residence time at 1,900 deg F. This increases to 0.05 seconds of additional residence time at 1,650 deg F and to 0.10 seconds at 1,450 deg F.
Typical industrial package boilers have a total flame residence time of about 0.2 seconds. The exit temperatures range from 1,600 to 2,000 deg F depending on the size of the combustion chamber. The flame mixing typically requires about 0.1 to 0.15 seconds for non-premixed flames, leaving only 0.05 to 0.10 seconds for CO burnout. The range of temperatures in the radial direction varies from 400 deg F at the wall to 2,800 deg F in the center of the flame. To achieve 1ppm CO would require the flame to be very narrow, long and well away from the cool walls to avoid CO quenching (which occurs at ~1,500 deg F).

[See submittal for list of references for graph of NOx and CO vs time, temperature at 10% EA premixed.]

[See submittal for graph of NOx and CO vs time, temperature at 10% EA premixed.]

Response: See the response to comment EPA-HQ-OAR-2002-0058-2960.1, excerpt 124.

Commenter Name: Wayne Smith
Commenter Affiliation: Westlake Chemical Corporation
Document Control Number: EPA-HQ-OAR-2002-0058-2785.1
Comment Excerpt Number: 4

Comment: Criteria Pollutant Concerns: The Proposed Rule relies on Carbon Monoxide emissions as a surrogate for organic HAP emissions. While this may seem to be a logical and simplified approach, Boilers and Process Heaters must also achieve Nitrogen Oxides emissions limitations. Forcing higher oxygen levels in combustion units to achieve extremely low Carbon

Monoxide emissions limitations will make compliance with Nitrogen Oxides emissions limitations more difficult, if not impossible.

Response: See the response to comment EPA-HQ-OAR-2002-0058-2697.1, excerpt 2.

Commenter Name: Dale A. Riddle
Commenter Affiliation: Seneca Sustainable Energy
Document Control Number: EPA-HQ-OAR-2002-0058-2866.1
Comment Excerpt Number: 5

Comment: Seneca's operations will actually decrease the amount of HAPs emitted into our local airshed once our renewable energy plant is up and running. As discussed above, open burning results in substantial increases in HAP emissions as compared to controlled combustion. Seneca will provide 25% of its fuel from sources that otherwise would be burned under the Oregon Forest Protection Laws in the field. In its paper published by Paul Lemieux of EPA's National Risk Management Research Laboratory, Benzene emissions from the open burning of Douglas-fir slash were estimated at 196 mg/kg. This means that by diverting enough slash from open burning to constitute approximately 25% of our fuel needs, Seneca's plant will result in more than a 7-tonper-year reduction in Benzene emissions. Emissions of other organic air toxics, such as styrene and toluene, are similar orders of magnitude higher than the emission rates associated with our controlled combustion in our renewable energy plant and, as noted above, the reduction in motor vehicle trips and the elimination of natural gas in our dry kilns will also reduce HAP emissions, such that our renewable energy plant is estimated to reduce total HAP emissions by more than 20 tons per year.

Response: The EPA thanks the commenter for their input, but the EPA did not have ample time or data to analyze the potential impacts the rule may have on open burning.

Commenter Name: Frank Kohlasch
Commenter Affiliation: Minnesota Pollution Control Agency
Document Control Number: EPA-HQ-OAR-2002-0058-2773.1
Comment Excerpt Number: 6

Comment: Mercury emission limits for major and area sources will help states meet their Clean Water Act Total Daily Maximum Load's (TMDL) for mercury. Because mercury is a regional pollutant, no state alone can impose air emission limits for mercury to fully address their mercury water quality impairments. In approving Minnesota's TMDL for mercury impairments, EPA agreed that it will use its authorities to address mercury as a regional pollutant and establish standards that will reduce releases of mercury to the atmosphere. The MPCA supports EPA's proposed standards for mercury from major and area source standards, and believes they will significantly reduce outstate contributions to mercury atmospheric deposition in Minnesota.

Response: EPA thanks the commenter for their input.

Commenter Name: Richard Caserta
Commenter Affiliation: Red Hill Grinding Wheel Corp
Document Control Number: EPA-HQ-OAR-2002-0058-2996
Comment Excerpt Number: 7

Comment: EPA's focus on individual HAPs has resulted in a failure to recognize the critical interplay between emissions controls and emissions of other pollutants. For example, we are concerned that the controls necessary to meet the stringent emissions limitations for CO will result in increased energy usage, with the concomitant increase in emissions of NOx and other pollutants. Further, EPA failed to account for this interrelationship in its economic analysis.

Response: See the response to comment EPA-HQ-OAR-2002-0058-2690, excerpt 7.

Commenter Name: Robert L. Garfield
Commenter Affiliation: Food Industry Environmental Council
Document Control Number: EPA-HQ-OAR-2002-0058-2718.1
Comment Excerpt Number: 7

Comment: EPA's focus on individual HAPs has resulted in a failure to recognize the critical interplay between emissions controls and emissions of other pollutants. For example, we are concerned that the controls necessary to meet the stringent emissions limitations for carbon monoxide (CO) will result in increased energy usage, with the concomitant increase in emissions of nitrogen oxide (NOx) and other pollutants. Further, EPA failed to account for this interrelationship in its economic analysis.

Response: See the response to comment EPA-HQ-OAR-2002-0058-2690, excerpt 7.

Commenter Name: Cathy S. Woollums
Commenter Affiliation: MidAmerican Energy Holdings Company
Document Control Number: EPA-HQ-OAR-2002-0058-2786.1
Comment Excerpt Number: 10

Comment: Optimizing combustion to minimize CO emissions comes at the price of increased nitrogen oxide ("NOx") emissions. MidAmerican's significant experience with retrofitting low NOx burners with over-fire air on large coal-fueled boilers has demonstrated that optimizing the combustion process to reduce NOx increases CO and, the converse is, likewise, true – when adjusting combustion to control CO, NOx increases. The EPA does not appear to have taken this increase in criteria pollutant into consideration when setting these very stringent CO limits. In conclusion, the Boiler MACT should allow facilities to implement combustion optimization instead of proposing compliance with stringent and, in some instances, unattainable CO emission limits.

Response: See the Preamble for response on how we addressed and revised CO limits, and their relationship to NOx.

Commenter Name: Russ A. Wozniak
Commenter Affiliation: Dow Chemical Company
Document Control Number: EPA-HQ-OAR-2002-0058-2632.1
Comment Excerpt Number: 15

Comment: In addition, the combustion performance of gas fired boilers strongly depends on positions of fuel nozzles, air damper stroking, burner register positions, etc. In order to attempt to comply with a CO level of 1 ppmvd @ 3% O2 on a 30 day rolling average these adjustments will have to be made more frequently than from an annual tune-up. The operator will have to frequently shutdown the equipment, make these adjustments, and then restart. Such cycles will increase annual emissions because CO is higher during shutdowns and startups. Hourly CO CEMS data from a Gas2 low CO emission boiler at one of our sites was extended to a 30 day rolling average. The following plot shows that it would be extremely difficult to keep such a boiler in compliance even with minimal equipment adjustments. [See submittal for figure "CO Histogram – 30 day rolling average, Boiler 1."]

Note: Each bar represents the % of time that CO is above a certain concentration between 2 and 4 ppmv.

Response: Noting the low CO limits for the Gas 2 category at proposal, the EPA has adjusted these limits to a more reasonable number which should minimize the adjustments and impact on boiler operations.

Commenter Name: Russ A. Wozniak
Commenter Affiliation: Dow Chemical Company
Document Control Number: EPA-HQ-OAR-2002-0058-2632.1
Comment Excerpt Number: 16

Comment: The proposed CO Level of 1 ppmv at 3% Oxygen Should Not Be Promulgated Because it will Have An Unintended Consequence to Increase Thermal NOx Emissions. The addition of more fuel to increase the load and combustion source firing temperature may result in a small reduction of CO concentrations from boilers and heaters. However, this same increase is not fuel efficient and will also result in an increase of thermal NOx emissions from this same source. Increasing NOx emissions in order to reduce CO emissions is not a good approach to solving air pollution problems. NOx emissions are a precursor to ground level ozone formation and EPA is currently reconsidering the level for the 8-hour ozone standard. Without doubt, a lower ozone standard will require the reduction of thermal NOx emissions. Thus, EPA should not promulgate a CO level that will in turn cause NOx emissions to increase.

Response: See the response to comment EPA-HQ-OAR-2002-0058-2960.1, excerpt 124 regarding emissions increases and the response to comment EPA-HQ-OAR-2002-0058-2697.1, excerpt 2 regarding the impact on ozone non-attainment areas.

Commenter Name: Traylor Champion
Commenter Affiliation: Georgia-Pacific LLC
Document Control Number: EPA-HQ-OAR-2002-0058-2745.1
Comment Excerpt Number: 2

Comment: * Control technologies – There are 5 different pollutants regulated by Boiler MACT – PM, CO, HCl, Hg and dioxin/furan. The control of these pollutants can directly impact emissions of other pollutants or impact the performance of existing pollution control devices:
o Pollutant interactions – The most notable is the relationship between NOx and CO (and possibly dioxin/furan). The inverse relationship between NOx and CO is well established. The generation of both pollutants is a function of combustion conditions in the furnace – excess air, time, temperature and turbulence. CO emissions are minimized by having high excess air and significant time at high temperature and turbulence. These same conditions maximize NOx emissions. Most industrial boilers control NOx emissions by controlling combustion conditions in the furnace utilizing a combination of techniques including low excess air, low NOx burners, staged combustion, and flue gas-recirculation. The requirement to also control CO emissions may require development of a strategy for controlling one of the two by controlling combustion conditions and the other by back-end cleanup. If it turns out that the most cost effective solution is to control CO in the furnace and NOx by back end clean-up, existing NOx control systems will have to be replaced with SCR or SNCR.
o Interaction Between Control Technologies – Control of Hg and dioxin/furan may require utilization of activated carbon injection (ACI). The additional particulate loading in the gas stream will have to be collected by the PM control device. The net impact on PM emissions won't be known until the ACI system is operational and stack PM emissions are measured.
In these situations, the optimal control strategy would be a staged implementation consisting of installation of new control technology to address the Boiler MACT pollutants followed by corrective action to address the impact on other pollutants or pollution control devices. The time constraints make this impractical and compliance costs may increase as a result.

Response: See the Preamble for response.

Commenter Name: Mick Baranko
Commenter Affiliation: Douglas County Forest Products
Document Control Number: EPA-HQ-OAR-2002-0058-2856.1

Comment Excerpt Number: 1

Comment: We respect EPA's job is to protect air quality. However, the existence of biomass boilers to receive woody material means that hundreds of thousands of tons of forest slash is burned in controlled combustion rather than in open burn piles. As EPA research has previously established, routing biomass to boilers has a profound beneficial impact on hazardous air pollutant emissions. For example, in its paper published by Paul Lemieux of EPA's National Risk Management Research Laboratory, benzene emissions from the open burning of Douglas fir slash was estimated at 196 mg/kg. [Reference: Lemieux et al, Emissions of Organic Air Toxics from Open Burning: A Comprehensive Review; Table 6; Progress in Energy and Combustion Science 30 (2004)] The estimated benzene emissions from the controlled burning of Douglas fir slash in a biomass boiler is less than 5 mg/leg. This means that every ton of slash burned in the forest results in approximately 40 times more benzene than had that same ton been burned in a biomass boiler. By adding unduly burdensome regulations that force wood products companies such as ours to stop burning biomass, EPA will cause.the diversion of slash to open burning with the net result being a significant increase in hazardous air pollutant emissions.

Response: See the response to comment EPA-HQ-OAR-2002-0058-2866.1, excerpt 5.

Commenter Name: Dean C. DeLorey
Commenter Affiliation: The Amalgamated Sugar Company
Document Control Number: EPA-HQ-OAR-2002-0058-2833.1
Comment Excerpt Number: 2

Comment: We request that EPA carefully consider the attached comments. Future costs for the proposed rules are likely unaffordable and could seriously jeopardize the future operation of TASCO facilities and all other U.S. sugar beet companies. Reductions in domestic sugar production would shift operations to other countries with less stringent emissions control requirements. As a result, net overall worldwide emissions would actually increase as a result of these proposed rules.

Response: The EPA may only consider U.S. emissions when considering emissions impacts from this rule, so while the EPA appreciates the comment, considering worldwide emissions is outside the scope of this rule. See the Memorandum "Revised Methodology for Estimating Cost and Emissions Impacts for Industrial, Commercial, Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants – Major Source 2011" in the docket for a discussion of costs specific to the affected US facilities.

Commenter Name: Robert Thornton
Commenter Affiliation: International District Energy Association
Document Control Number: EPA-HQ-OAR-2002-0058-2918.1
Comment Excerpt Number: 4

Comment: Low emissions in one pollutant may negatively affect the ability to reduce emissions of other pollutants. The proposed standards are seriously flawed because they fail to recognize the interactivity of a range of pollution controls. For example, emissions of CO and NOx are inversely related. Reducing NOx emissions leads to increasing CO emissions, while reducing CO emissions leads to increasing NOx emissions.
It appears that of the 14 MACT floor pool sources used to set standards for liquid fuel boilers, 6 of the 14 sources do not have low NOx burners. It is likely that these sources, operating with low CO emissions, had high NOx emissions. Sources that have installed low NOx burners may have higher CO emissions.
The proposed MACT standards put regulated entities in the untenable position of being unable to meet both the proposed MACT standards as well as current standards for non-HAP emissions.

Response: See the response to comment EPA-HQ-OAR-2002-0058-2740.2, excerpt 9.

Commenter Name: Chris Korleski
Commenter Affiliation: Ohio EPA
Document Control Number: EPA-HQ-OAR-2002-0058-2818.1
Comment Excerpt Number: 4

Comment: The proposal has the potential to increase emissions of certain criteria pollutants, such NOx, as a result of the pollution control approaches required for other pollutants in the rule.

Response: See the response to comment EPA-HQ-OAR-2002-0058-2690, excerpt 7.

Commenter Name: Joe Muehlbach
Commenter Affiliation: Quad/Graphics
Document Control Number: EPA-HQ-OAR-2002-0058-2898.1
Comment Excerpt Number: 4

Comment: As a company running several manufacturing plants in an ozone non-attainment zone as well as impacted by PM2.5 non-attainment we are particularly interested in any action that has the potential to increase NOx emissions. Concerns have been raised by the Wisconsin Department of Natural Resources that the pollution control approaches required for other pollutants in the rule may have the unintended consequence of increasing NOx emissions. Tremendous efforts have been made in Southeastern Wisconsin resulting in measurable improvements to the air quality and the state is now on track to comply with both the federal ozone and PM2.5 standards and anything that may set back those efforts are cause for concern.

Response: See the Preamble for response.

Commenter Name: Ted Michaels
Commenter Affiliation: Energy Recovery Council
Document Control Number: EPA-HQ-OAR-2002-0058-2831.1
Comment Excerpt Number: 5

Comment: EPA's pollutant-by-pollutant approach fails to account for the interrelationships among pollutant emissions. Emissions from combustion/air pollution control systems are interdependent – the presence or control of one can affect the control of others. These interrelationships must be considered in order to assure that unit emission reductions are effective for all pollutants, not just one at time. Examples of these interrelationships are: Carbon Monoxide (CO) and Nitrogen Oxides (NOx) – CO is a product of incomplete combustion of organic materials and a function of oxygen levels, temperature, air/fuel mixing (turbulence) in the combustion zone, and residence time. NOx formation is dependent on the amount of fuel-bound nitrogen compounds, air-to-fuel ratio, and flame temperature. Because combustion conditions affect both pollutants the two are interrelated. Attempts to control CO can lead to increases in NOx and vice versa. In California, biomass-to-energy facility operators meet NOx permit limits in part by balancing the combustion process between emissions of CO and NOx with the result that CO emissions are significantly higher than EPA's proposed Major Boiler MACT standards. Attempts to reduce emissions of CO would result in increases in emissions of NOx, leading to an untenable situation. The submittal contains two graphs that plot hourly CEM-measured CO and NOx readings over a ten day period at two stoker-fired California biomass-to-energy boilers – Burney Mountain Power in Burney and Mount Lassen Power in Westwood. The plots demonstrate the inverse relationship between CO and NOx. The third graph shows the same interrelationship using 24-hour average plots over an annual period at Burney Mountain Power.

These concerns are echoed in a report by the Maine Department of Environmental Protection which analyzed CEM and stack test data from 19 biomass boilers, stating "Test data demonstrated the relationship between NOx and CO. As NOx levels increased CO levels decreased and vice versa."[Maine Department of Environmental Protection, "Carbon Monoxide Variability in Maine Wood Fired Boilers, February 2010, page 2. Attachment to letter from James P. Brooks, Bureau Director, State of Maine Bureau of Air Quality to James Eddinger, USEPA, February 4, 2010.] The Maine DEP stated "We are also concerned that EPA may develop standards that do not take into account the NOx controls required for many of the Maine facilities and the effect that controlling for CO, which inversely affects NOx, as well as other pollutants."[3 Letter James P. Brooks, Bureau Director, State of Maine Bureau of Air Quality to James Eddinger, USEPA, February 4, 2010.] See Attachment 1 which includes both the Maine DEP report and letter.

Nitrogen Oxides (NOx), Total Particulate Matter (PM), and Opacity – Selective Non-catalytic Reduction (SNCR) is frequently used for combustion source NOx control. SNCR involves injecting a reagent (urea or ammonia) into the furnace where it reacts within a temperature window to chemically reduce NOx. Control efficiency is limited by reagent/flue gas mixing and reaction kinetics. When pushed to higher performance unreacted ammonia "slip" increases which in the presence of SO_3 and HCl in the flue gas forms condensable ammonium sulfate/chloride particulate matter and potentially high opacity stack plumes.

Sulfur Dioxide, Hydrogen Chloride and Mercury – Boiler burning wastes or fuels with significant sulfur and chlorine contents will form mercury species (e.g., mercury chloride) that are easier to collect using carbon adsorption and PM control systems. Boilers burning wastes without sulfur and chlorine emit mercury in elemental form which is harder to collect.

These interrelationships show the technical incompatibility of setting floors on a pollutant-by-pollutant basis.

Response: See the Preamble for responses on how we addressed CO limits, control device interactions, and the pollutant-by-pollutant approach.

Commenter Name: David M. Kiser
Commenter Affiliation: International Paper Company
Document Control Number: EPA-HQ-OAR-2002-0058-2777.1
Comment Excerpt Number: 6

Comment: Combustion processes have been "tuned" in recent decades to reduce emissions of NOx. NOx reduction technology, i.e., starving the combustion process of oxygen and lengthening the combustion zone to reduce peak flame temperature, is in direct conflict with conditions needed to minimize CO. Current "optimum" combustion conditions or technology cannot achieve the proposed limits on a continuous basis. Attempts to lower CO will increase NOx emissions and result in adverse permitting and environmental consequences.

Response: See the response to comment EPA-HQ-OAR-2002-0058-2960.1, excerpt 124 regarding emissions increases and the response to comment EPA-HQ-OAR-2002-0058-2697.1, excerpt 2 regarding the impact on NOx permits.

Commenter Name: Kevin M. Dempsey
Commenter Affiliation: American Iron and Steel Institute
Document Control Number: EPA-HQ-OAR-2002-0058-2998.1
Comment Excerpt Number: 7

Comment: But unlike natural gas, which is generally stored as a commodity when not consumed, coke oven gas must be flared as a waste gas to ensure a safe environment if not immediately usable at a facility. As a result, creating incentives which cause operators of coke oven gas-fired units to fuel-switch (even to natural gas) would result in significant net emissions increases. That is because the facility would necessarily combust both the coke oven gas (at a flare) and the additional fossil fuel necessary to generate sufficient heat for its operations. Simply put, any standard that creates a disincentive to recover energy from process gases is bad for the environment and thus contrary to the goals of the CAA. Extending work practice tune-up standards to coke oven gas or process gas-fired boilers will ensure that there is no environmentally detrimental incentive to displace coke oven gas or process gas with natural gas or other fuels in the boiler and flare those recoverable energy sources.

Response: EPA has modified the definition of natural gas to be consistent with the boiler New Source Peformance standards, incorporate a fuel specification for hydrogen sulfide and mercury content, and also added an exemption from the rule for boilers that serve as control devices for other MACT source categories. EPA expects these changes will increase the number of gases qualifying as gas 1, thereby reducing the impact that process gases will be flared. We have continued to measure the costs to the remaining gas 2 units, mostly units firing coke oven gas, as costs associated with controlling these units instead of the costs of flaring the gases. EPA does not have the information available to determine how many of the remaining gas 2 units will install control vs. flare the gas and purchase natural gas.

Commenter Name: Deb Hastings
Commenter Affiliation: Texas Oil and Gas Association
Document Control Number: EPA-HQ-OAR-2002-0058-2857.1
Comment Excerpt Number: 7

Comment: Fully consider the increase in NOx, sulfur dioxide (SO2), volatile organic compounds (VOC) and particulate matter (PM) and the potential loss in boiler and process heater energy efficiency that result from forcing an excessively low CO emission.

Response: See the response to comment EPA-HQ-OAR-2002-0058-2960.1, excerpt 124.

Commenter Name: A. Steven Young
Commenter Affiliation: Association of Independent Corrugated Converters
Document Control Number: EPA-HQ-OAR-2002-0058-2899.1
Comment Excerpt Number: 9

Comment: EPA's focus on individual HAPs has resulted in a failure to recognize the critical interplay between emissions controls and emissions of other pollutants. For example, we are concerned that the controls necessary to meet the stringent emissions limitations for CO will result in increased energy usage, with the concomitant increase in emissions of NOx and other pollutants. Further, EPA failed to account for this interrelationship in its economic analysis.

Response: See the response to comment EPA-HQ-OAR-2002-0058-2690, excerpt 7.

Commenter Name: Allyn Ford

Commenter Affiliation: Roseburg Forest Products
Document Control Number: EPA-HQ-OAR-2002-0058-3163
Comment Excerpt Number: 9

Comment: Additionally, most of Roseburg Forest Products facilities are already required to control NOx emissions at the lowest achievable levels and have no room in their NOx permit limits for combustion modifications to reduce CO, since these modifications universally have an inverse impact on NOx emissions. Roseburg Forest Products questions whether EPA looked at the NOx emission rates of the best performing 12% of sources, from which the CO limits were established, to ensure that those sources are not only compliant with permit limits, but also have demonstrated no significant impact to NAAQS. It is possible that the best performing sources of CO emissions do not struggle with the opposing NOx emission limitations that many other facilities face. EPA is proposing opposing pollutant requirements that will likely lead to facilities being out of compliance with either CO or NOx limits at any given time.

Response: See the response to comment EPA-HQ-OAR-2002-0058-2697.1, excerpt 2.

Commenter Name: Douglas J. Van Pelt
Commenter Affiliation: ExxonMobil
Document Control Number: EPA-HQ-OAR-2002-0058-2968.1
Comment Excerpt Number: 13

Comment: CO and NOx emissions are both dependent on the residence times and temperatures of the flue gas in the firebox, but in different ways. Low CO emissions are favored by high firebox temperature, high O2, rapid mixing, and long residence times. NOx is an undesirable combustion byproduct favored by high temperatures, high O2, and rapid mixing via "thermal", "prompt", and "fuel" NOx mechanisms. As CO decreases, NOx increases and vice versa, so emissions control in any fired equipment is a trade-off between the two. See submittal for Figure 8.

For NOx control, designers aim to reduce both temperature of the furnace and time that the reactants and products of combustion stay in the furnace, while ensuring adequate heat transfer to the process or boiler tubes. However, complete oxidation of CO is needed for very low emissions like 1 ppm, which approaches "ideal" combustion. To do this, high temperatures are required > 1900 F and long residence times. However this is impractical to achieve in industrial equipment where large heat sinks quickly quench the flames. Most industrial package boilers have approximately 0.2 second of total residence time in the furnace, of which 0.1-0.15 second is required for flame mixing. The remaining 0.05-0.1 second of residence time is what can be tolerated before the flue gas is quenched by the colder process or boiler tubes. For most boilers and process heaters achieving low NOx emissions, there is insufficient time at temperature to oxidize CO to 1 ppm.

Response: See the Preamble for response on how we addressed and revised CO limits.

Commenter Name: Chris Korleski
Commenter Affiliation: Ohio EPA
Document Control Number: EPA-HQ-OAR-2002-0058-2818.1
Comment Excerpt Number: 20

Comment: Many boilers in ozone non-attainment areas have also been modified to achieve reductions in NOx emissions. The first basic step in controlling NOx emissions, especially industrial sized boilers, is to apply combustion modifications which can result in higher carbon monoxide emissions. It is not clear that the evaluation EPA performed in proposed its MACT rule addresses the necessity to meet NOx requirements or the physical changes that have been made to boilers in order to meet these limits stemming from other EPA rules. In some cases, staging the combustion and increasing residence
time in the- combustion zone could theoretically result in more complete combustion ,c)f organic HAPs. Or in other types of modifications, less complete combustion may be achievable while meeting the NOx requirement. At a minimum, US EPA needs to recognize that NOx requirements are in place for boilers which may impact the ability to meet the proposed carbon monoxide emission limits (refer to discussion on CO emission limits).

Response: See the Preamble for response on how we addressed and revised CO limits.

Commenter Name: American Crystal Sugar Company and Michigan Sugar Company
Commenter Affiliation: Patricia Hansen and Steven Smock
Document Control Number: EPA-HQ-OAR-2002-0058-2970.1
Comment Excerpt Number: 23

Comment: We do have concerns that the proposed rule is overly aggressive. As stated above there is evidence that a significant amount of the data and resulting emission limits need to be closely examined. The MACT floors need adjustment. Failure to do so may result in an impossible situation for nearly all boiler operators. Any reduction in domestic sugar production as a result of the proposed regulations will result in an increase of imported sugar. This has the potential for actually resulting in a world wide net increase in air pollution emissions since the US is a leader in efficient production and few sugar exporting countries have the same level of emission control. The impact evaluation of the rule must include this likely scenario.

Response: See the response to comment EPA-HQ-OAR-2002-0058-2833.1, excerpt 2 regarding emissions from importing sugar and the Preamble for a response regarding limits.

Commenter Name: David O'Keefe
Commenter Affiliation: USEC, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-3122

Comment Excerpt Number: 25

Comment: Energy audits/assessments — 1 percent efficiency improvement. The assumed energy efficiency improvement is questionable. The proposal and WA assume that many units are operating inefficiently and that unit owners have not evaluated unit efficiency. This is likely not the case and the assumed efficiency improvement will not occur because the proposal will have the unintended consequence of decreased efficiency because of the CO emission standard. A normal step taken to reduce CO is to increase excess air (oxygen). This reduces unit efficiency because although there is more complete combustion, more heat is exhausted with the excess air. Additionally, a second unintended consequence is an increase in NO emissions because there is more oxygen available to form NO, while in the critical temperature range.

Response: Boiler tune-ups can improve the efficiency of a boiler from 1 to 5%, depending on its operating characteristics. While some boilers may have performed tune-ups there is still a large percent which have not. Using these two factors, an estimated efficiency improvement of 1% is considered a conservative estimate. See the preamble for a discussion on NOx emissions and boiler efficiency as they relate to the CO limit.

Commenter Name: David O'Keefe
Commenter Affiliation: USEC, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-3122
Comment Excerpt Number: 36

Comment: CO emission limits and work practice standards. The CO emission standard could result in reduced efficiency and increased NOT emissions. A normal step taken to reduce CO is to increase excess air (oxygen) this can reduce unit efficiency because although there is more complete combustion more heat is exhausted with the excess air. Decreased efficiency results in more fuel burned and increased emissions.

Additionally, NOT emissions can increase because more oxygen is available to form NO„ while in the critical temperature range. Affected units with NOT emission limits may find it difficult or impossible to simultaneously achieve both CO and NO, emission limits. This is especially relevant to those affected units where steps have been taken to reduce NOT emission through low-NO„ burners, flue gas recirculation, etc. If there is a net increase in other emissions, including NO,, the benefits of regulating non-dioxin organic HAPs (using CO as a surrogate) under the MACT are questionable and should be reconsidered.

An increase in NOT emissions will impact ambient air quality and increase social costs. Decreased efficiency will result in an increase in many air pollutants. These negative costs impacts should be included in the cost impact analysis.

Response: See the response to comment EPA-HQ-OAR-2002-0058-2960.1, excerpt 124.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 53

Comment: Most boilers are designed to mix fuel and air at an appropriate ratio, and to provide sufficient residence time for the fuel to combust completely. Obviously, these factors are fuel-dependent. A gaseous fuel will require less time for complete combustion than a liquid fuel, which in turn requires less time to burn than a solid fuel. The need for longer residence time is why the radiant section s in solid-fuel fired boilers are larger than for gas-fired units. The size of the boiler is typically optimized to allow for complete combustion, while minimizing the cost of construction materials. If the construction cost were not a concern, a new boiler could be designed with additional residence time to complete the combustion process and minimize CO emissions.

Unfortunately, increasing the size of the furnace is not an option for existing units. For these units, the strategy for reducing CO emissions is typically to raise the level of excess oxygen. The increase in oxygen concentration has two positive effects. First, it acts to overcome poor distribution of the fuel. Second, it increases the flame temperature, which speeds up the combustion reactions, allowing more complete combustion to occur for the same residence time. However, there are a number of negative impacts associated with operating a boiler at higher levels of excess oxygen. Many boilers do not have sufficient fan capacity to run with elevated excess oxygen at the high end of the load range. Therefore, these units would not be able to operate at capacity under this strategy. A site might have to add another boiler to offset the reduction in steam generating capacity.

Minimizing excess oxygen in boiler applications is a key feature for maximizing boiler efficiency. The boiler efficiency is defined by the amount of combustion air that is present, and the difference between the ambient temperature and the stack exhaust temperature. The more air that is heated up through the combustion process, the more heat is lost to the atmosphere, causing the boiler to be less efficient. A less efficient boiler will require more fuel to be fired to produce a given amount of steam. The additional fuel firing results in higher operating costs, and higher greenhouse gas emissions.

Minimizing excess oxygen is also a primary strategy for reducing NOx emissions from a boiler. The NOx formation mechanisms are dependent upon the temperatures in the flame zone, and the stoichiometry. Reducing the level of excess oxygen reduces the peak flame temperature, which reduces the rate at which the nitrogen in the air dissociates. There is less monatomic nitrogen available to be oxidized to form "thermal NOx". Similarly, if there is less oxygen present, the monatomic nitrogen is less likely to be oxidized (and more likely to react with a second monatomic nitrogen to form diatomic nitrogen). This reduces both the amount of thermal NOx, and the "fuel NOx" (NOx that is formed by the release of fuel-bound nitrogen). Therefore, increasing the level of excess oxygen will result in higher NOx emissions.

Response: See the response to comment EPA-HQ-OAR-2002-0058-2960.1, excerpt 124.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 54

Comment: Low-NOx burner (LNB) designs for gas-fired boiler applications manipulate the stoichiometry within the flame to minimize NOx formation. These designs establish a fuel-rich zone for the initial phase of combustion, and then add air at a later stage in the outer regions of the flame. In the initial phase, there is not sufficient oxygen available to form significant amounts of NOx, and in the secondary phase, the flame is much cooler, which also inhibits NOx formation. However, these burners often operate with CO emission up to 10 ppmvd in the upper part of the load range. At mid loads, the CO begins to increase near 50 ppmvd, and at low loads, it may exceed 100 ppmvd. These low-NOx burners will not be able to achieve CO emissions as low as 1 or 2 ppmvd. As the EPA is on the verge of establishing a lower ozone standard, many more facilities will likely be installing low-NOx burners.

The data from units used to determine the floor for the Gas1 boilers and heaters were reviewed to better assess the quality of the proposed CO limits. Specific information was obtained for 23 of the 91 units in the floor calculation (about one fourth of the sources). Of the 23 units that were investigated, 7 were no longer in service [We expect that the parent companies have already communicated these shutdowns to EPA as part of their comments.] In addition, the analysis showed that none of the units were equipped with state-of-the-art low-NOx burners, and many were equipped with conventional burners that were more than 30 years old (contrary to EPA's contention in the floor memo that replacement low-NOx burners will result in lower CO emissions). As stated previously, LNB are designed to stage the flame, and as a result have higher CO emission rates. A great majority of these units are smaller process heaters, which are not equipped with combustion controls or O2 analyzers. As such, they are typically operated at higher levels of excess air as a safety precaution, which is inefficient, but does serve to minimize CO emissions.

Response: See the Preamble for response on how we addressed and revised CO limits.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 55

Comment: The requirements of the National Fire Protection Act (NFPA) specify the minimum total airflow at which a boiler can operate, which is independent of the boiler load. This value is commonly 25 or 30 percent of the total airflow. As a result, boilers that are operating at loads less than 25 percent experience increasing levels of excess air because the fuel flow is decreasing with load, but the air flow remains fixed. The amount of excess air can become sufficiently high that it acts as a heat sink and reduces the flame temperature. The cooling of the flame slows the combustion kinetics, and often produces higher CO emissions. Therefore, low CO emission limits could restrict the minimum load capability of a boiler. Since boilers are often run at minimum load (either in warm standby mode, or due to low steam demand), this results in the boiler "idling" at a higher load than was previously necessary. Obvious outcomes of operating at higher load are increased fuel costs and a relative increase in greenhouse gas and other pollutant emissions.

Response: See the Preamble for response on how we addressed and revised CO limits.

Commenter Name: Alicia Oman
Commenter Affiliation: National Association of Manufacturers
Document Control Number: EPA-HQ-OAR-2002-0058-2845.1
Comment Excerpt Number: 61

Comment: The controls necessary to meet EPA's stringent proposed emissions limitations for CO will result in increased energy usage along with increased emissions of other pollutants.

EPA's proposed CO emissions limit arbitrarily and capriciously fails to recognize the dependency between CO and other emissions, which makes this rule impossible to implement in either process heaters or boilers. Requiring such extraordinarily low CO levels will have an adverse impact on other emissions such as NOx, PM, greenhouse gases (GHG) and even HAPs. Reducing CO to extremely low levels will require increased excess air levels which reduce efficiency, increasing the amount of fuel that must be fired and therefore increasing the total mass of other pollutants (i.e. HAPs, GHGs, NOx, SO_x, PM, etc.). For example, CO and NOx emissions are both dependent on the residence times and temperatures of the flue gas in the firebox, but in different ways. For most boilers and process heaters achieving low NOx emissions, there is insufficient time at temperature to oxidize CO to 1 ppm. As CO decreases, NOx increases and vice versa, so emissions control in any fired equipment is a trade-off between the two.

Response: See the response to comment EPA-HQ-OAR-2002-0058-2960.1, excerpt 124.

Commenter Name: Douglas J. Van Pelt
Commenter Affiliation: ExxonMobil
Document Control Number: EPA-HQ-OAR-2002-0058-2968.1
Comment Excerpt Number: 79

Comment: The proposed rule, which is a hazardous air pollutant rule, does not actually calculate HAP emissions from gas fired units and the potential reduction as a result of the proposed rule.

Based on a review of the supporting documents of the proposed rule, it appears EPA did not calculate the emission reductions or estimate the benefits associated with the HAP reductions. Failure to provide this information undermines the assessment of rule impacts, cost-effectiveness, and beyond the floor considerations.

EPA needs to calculate the HAP baseline and emissions post rule implementation to properly characterize the rule impact and costs, and to update the RIA.

Response: Emission estimates are provided for CO, THC, VOC, PM, Hg, non-Hg metals, dioxins/furans, HF, SO2, and HCl. It is demonstrated that VOC includes organic HAP, and to the extent that VOC are reduced, organic HAP would be reduced as well. No specific individual organic HAP calculations were estimated.

Secondary Impacts

Commenter Name: Ritchie Monteith
Commenter Affiliation: AbitibiBowater - Catawba Operations
Document Control Number: EPA-HQ-OAR-2002-0058-0849.1
Comment Excerpt Number: 5

Comment: Biomass boilers should be given special consideration. Biomass boilers are carbon neutral and beneficial to the environment. My mill has two biomass boilers. EPA should encourage the continued operation of biomass boilers. By setting unreasonable limits on biomass boilers, EPA will drive industry towards fossil fuel when EPA should be favoring biomass use.

Response: The emission limits are revised for the final rule, see the preamble for discussion. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source.

Commenter Name: Ritchie Monteith
Commenter Affiliation: AbitibiBowater - Catawba Operations
Document Control Number: EPA-HQ-OAR-2002-0058-0849.1
Comment Excerpt Number: 2

Comment: The Boiler MACT rule needs to be fixed. The rule, as proposed, will actually discourage industry from using biomass over more traditional fossil fuels or natural gas.

Response: The emission limits are revised for the final rule, see the preamble for discussion. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source.

Commenter Name: Thomas J. Christofk
Commenter Affiliation: Placer County Air Pollution Control District
Document Control Number: EPA-HQ-OAR-2002-0058-1598.1
Comment Excerpt Number: 1

Comment: The Placer County Air Pollution Control District does not support the MACT standards for biomass boilers for major and area sources as proposed. The proposed biomass boiler MACT standards have not been properly determined and will lead to adverse outcomes. Compliance would require the addition of "beyond the floor" control techniques that are not cost effective or required to protect human health or the environment. Some may even result in higher NOx emissions. Biomass boilers in Placer County (and throughout California) are already subject to existing regulatory permitting and inspection programs which ensure that boilers do not cause adverse impact to human or environmental health or degrade local air quality. Closure of existing plants and prevention of new plants would lead to significant increases in air emissions, as biomass wastes will be open burned or land-filled. Additional fossil fuels will need to be combusted to make up for the biomass energy.

Response: See the preamble for revised emission limits.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute and National Petrochemical and Refiners Association
Document Control Number: EPA-HQ-OAR-2002-0058-0851.1
Comment Excerpt Number: 3

Comment: The indirect consequences of some of these proposed requirements also were not included in the information provided to OMB. For instance, under the control schemes evaluated by EPA and used as a basis for their cost and burden estimates, the proposed CO limits for gas and oil would require increased fuel and electricity use and, as a result, increase CO_2 emissions. In fact, emissions of all pollutants other than CO would increase because of this increased fuel use. The low CO requirements proposed here will potentially lead to units being unable to meet the latest NOx emission limits set in other rules (e.g., NSPS Ja) and in State Implementation Plans (SIPs). This interaction calls into question the regulatory basis for those other rules and SIP requirements.

Response: See the preamble for discussion on CO limits.

Commenter Name: Thomas J. Christofk
Commenter Affiliation: Placer County Air Pollution Control District
Document Control Number: EPA-HQ-OAR-2002-0058-1598.1

Comment Excerpt Number: 4

Comment: PCAPCD believes that the standards are not needed to protect human health and the environment, and will likely lead to undesirable outcomes. District biomass boilers have been determined to pose low risk to human health, the environment, and ambient air quality. Existing boilers may be required to add Hg and HCl control technologies, such as activated carbon injection, carbon beds, or wet scrubbers and CO control technology (afterburners or catalytic oxidizers) to meet the proposed standards. These would be expensive, provide very small reductions, and would not likely be cost-effective. The standards might cause boilers to either stop utilizing biomass wastes or shutdown. This would significantly increase criteria, air toxics, and greenhouse emissions because the biomass wastes would be open burned (or land-filled), and additional fossil fuels would be required to replace the renewable energy that is produced by the biomass boilers.

Response: The emission limits are revised for the final rule, see the preamble for discussion. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source.

Commenter Name: A. Daniel White
Commenter Affiliation: T.R. Miller Mill Company, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-1597.1
Comment Excerpt Number: 4

Comment: Natural gas is not a viable option, as it is too expensive and unreliable. Wood biomass is a by-product of our manufacturing operations and is the only competitive fuel source for drying our products. If we don’t burn our biomass fuel, would you expect us to send this material to landfills?

Response: The emission limits and compliance options are revised for the final rule, see the preamble for discussion. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source.

Commenter Name: Los Angeles Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1778
Comment Excerpt Number: 12

Comment: Flambeau River Papers is a pulp and paper mill that has been in operation in Park Falls since 895. This mill has numerous boilers, the largest of which is the coal and biomass coal-fired boiler, number 6. Number 6 produces approximately 60 percent of the energy needs for the pulp and paper mill on a daily basis. In the four years we have owned and operated the

mill, we have been able to increase the efficiency of the boiler while at the same time decreasing our usage of coal from an historic average of 60 tons a day to being virtually free of coal today. The mill's previous owner's reliance on fossil fuels is truly what drove the mill into bankruptcy back in 2006. Sky rocketing fossil fuel costs, including coal and natural gas, increased the energy costs from a budget of approximately $400,000 a month to over 1.4 million a month. It was with this in mind that we made the commitment to ourselves, and the 13 employees at the mill, that we would become the first pulp and paper mill in North America to be fossil-fuel free. Because of that commitment, Flambeau River Papers has been able to reduce its carbon footprint by approximately 92,000 tons a year since 2005. This is another reason why we invested over $3 million to develop a new industrial biomass fuel boiler that burns at approximately 10,000 Btu's per pound to replace the coal that was used in the number 6 boiler in Park Falls. And it's the reason we are continuing to partner with the Department of Energy on a second generation biofuels project that we built next to the pulp and paper mill, and it will produce 17 million gallons of second generation transportation fuels, electricity, and have enough steam left over to replace 00 percent of the natural gas needs at the pulp and paper mill. With Flambeau River biofuels heat sinqed, the pulp and paper mill will be the first pulp and paper mill in North America to become fossil-fuel free. At Johnson Timber we utilize a small biomass boiler to produce the heat and steam required for the approximately 147 heating days at this facility. The biomass utilized by this boiler is bark from our manufacturing process. We have used this biomass for heat and steam for over 30 years so we can have that facility be virtually fossil-fuel free as well.
Our current plans to become fossil-fuel free at our facilities and continue to employ approximately 400 people through our organization in the forest products industry, however, is in jeopardy through the proposed stringent Boiler MACT rules. The pulp and paper mills in North America have been utilizing renewable biomass fuels for many decades. Approximately 65 percent of the energy needs in our industry come from carbon-neutral biomass. It would be unfortunate for this proud industry to have to cut back away from carbon-neutral fuel and have to convert to fossil fuels to meet the proposed rules.

Response: The emission limits are revised for the final rule, see the preamble for discussion. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source.

Commenter Name: Houston Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1876
Comment Excerpt Number: 17

Comment: There are unintended consequences of requiring the installation of pollution control devices that have not been demonstrated collectively to achieve the standards. For instance, the proposed CO for gas- and liquid-fired units will require operating at much higher oxygen levels than typical, which will lead to increased fuel use, and as a result, increased CO_2 emissions.

Response: See the preamble for discussion on CO limits.

Commenter Name: Houston Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1876
Comment Excerpt Number: 32

Comment: The proposed rule would cause many biomass boilers to convert to natural gas because that would be the only option they could afford. If Coastal switched, its annual natural gas cost would be $10 million a year and 150,000 tons of wood fuel would pile up somewhere. If all U.S. softwood panel and lumber producers switched, the annual cost would be $1- to $2 billion, we would consume 1- to 2 percent of total U.S. natural gas withdraws, which would significantly disrupt the natural gas market, and 20 million tons of wood fuel would be piled up somewhere to rot, which definitely wouldn't be green.

Response: EPA is not requiring fuel switching to natural gas in the final rule. Further, based on the data from best performing units in the biomass subcategory several units firing biomass are meeting the final emission limits. Therefore, EPA does not expect all of the units firing biomass to switch to natural gas as a compliance option; as a result, the EPA determined that the estimated landfilled biomass and increased natural gas usage noted by the commenter are overestimated. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 for further discussion on biomass.

Commenter Name: Houston Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1876
Comment Excerpt Number: 39

Comment: The boilers that are in use in the pulp and paper mills, in this state, have gone predominantly to biomass rather than natural gas or other fossil fuels. We are trying to push for carbon neutrality. We have a great deal of biomass available in Texas for use in our boilers and we are adapting that as much as we can.
We would like the EPA and the other -- both state and federal governments that are responsible for energy policy to pull together and to see if -- if -- make sure that what we do in one area doesn't impair the incentives that are in place for biomass use.
And we would just urge EPA to look at that issue and to make sure that all of these policies are running consistently with each other.

Response: The emission limits are revised for the final rule, see the preamble for discussion. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source.

Commenter Name: Los Angeles Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1778
Comment Excerpt Number: 43

Comment: All of our plants employ the best available technology as defined here in California. And our engineers to date have found no retrofits or mods that would meet the entire suite of regulations. I would point out that efforts to reduce carbon monoxide will, in our plants, invariably reduce -- increase emissions of NOx, which is an undesirable reaction.

Response: See the preamble for discussion on revised limits.

Commenter Name: Los Angeles Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1778
Comment Excerpt Number: 49

Comment: At the Hueneme mill we recycle paper, manufacture new paper products and we burn primarily natural gas. And we're the first in the United States to install a functioning working NOx catalyst. However, efficiency efforts in recent years has prompted us to transport rejected process material and water treatment system residues, mostly biomass, for burning as fuel at a boiler at another site here in California, also likely to be affected by the Boiler MACT rule.
It is likely that the rules might make it so expensive to use these alternative fuels that its use will cease and we will have to find landfill space to dispose of an otherwise fuel.

Response: The emission limits are revised for the final rule, see the preamble for discussion. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source.

Commenter Name: Houston Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1876
Comment Excerpt Number: 69

Comment: The proposed regulations will negatively impact the use of biomass fuels for industrial boiler use. The wood products industry has been using clean wood residuals as a primary fuel for decades. In other words, we were green before green was cool. The current administration touts the use of biomass fuels as part of

the new energy policy. On one hand, the USDA has given away over $148 million under the BCAP program for fuels that were already being used and now these regulations will restrict the use of these biomass fuels in the future. Any new business models that may be contemplating the use of biomass fuels may find the cost of the regulation prohibitive. To me this is another case of one body of government not acting in concert with the direction of another body of government.
Conversion of a wood products plant to natural gas is not economically viable. In our case, we have calculated that the increase in operating costs to use natural gas to be $31 million annually. That would be a 34 percent increase in operating costs at a time when the industry has sustained multiple years of losses, and would not be economically sustainable.

Response: The emission limits are revised for the final rule, see the preamble for discussion. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source.

Commenter Name: Houston Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1876
Comment Excerpt Number: 124

Comment: The forest industry has been, and continues to be, the largest consumer of biofuels. The rule as proposed ironically would impede environmental progress that many companies are achieving through greater and more efficient use of carbon-neutral biomass and would force the use of fossil fuels, which is face far less stringent requirements under the proposed rule.
Norbord suggests that the EPA requires this approach to recognize the carbon-neutral contribution of the biomass boilers in existence and ensure that these boilers are not penalized because they used an inherently cleaner fuel from the start.

Response: The carbon emissions from biomass is not within the scope of this rulemaking. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source, and see the preamble for the revised limits.

Commenter Name: Arlington Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1779
Comment Excerpt Number: 1

Comment: My written statement provides more details, but our primary concern is that EPA's rules as drafted would be unsustainable for the forest products industry. Indeed, EPA's proposals would create serious disincentives for the use of biomass and thereby increase use of fossil fuels, which we believe is counterproductive and contrary to the President's own energy policy.

Response: The emission limits are revised for the final rule, see the preamble for discussion. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source.

Commenter Name: Randolph Price
Commenter Affiliation: Consolidated Edison Company of New York
Document Control Number: EPA-HQ-OAR-2002-0058-1869.1
Comment Excerpt Number: 1

Comment: CECONY, as a member of the Clean Energy Group, endorses the comments provided by that group under separate cover. CECONY's individual comments, provided below, focus on the proposed rulemaking's regulation of liquid fuel and the way MACT floor values have been established for liquid-fueled units. Specifically, the Company is concerned with both a perceived deficiency in the data collection process and the adverse impact to Company steam system operations that will likely result from the rulemaking's failure to subcategorize liquid-fueled units. The use of residual oil in the CECONY steam system is essential to the maintenance of that system's reliability. During the coldest winter months, the New York State Public Service Commission requires that limited natural gas supplies be preferentially provided to residential and commercial customers. It is during such periods that the maximum output of the steam system is required for heating, and, consequently, the steam system boilers use residual oil as fuel to increase the availability of gas for residential and commercial use. This ability to use residual oil in the steam system boilers ensures that there is sufficient natural gas for preferred customers and that there is sufficient steam to heat the commercial and institutional buildings within the CECONY district steam system.

Response: See the preamble for discussion regarding subcategory definitions.

Commenter Name: Thomas C. Ludlow
Commenter Affiliation: JWTR, LLC
Document Control Number: EPA-HQ-OAR-2002-0058-1870
Comment Excerpt Number: 1

Comment: We employ more than 52 Oregonians and hope to be able to expand our employment by at least 40 people directly and an additional 20 people indirectly with the completion of the planned 35 Megawatt biomass electric facility in Klamath Falls.

As a timber company, we will be supplying the wood chips and forest waste to the proposed Klamath Biomass Facility as well as other timber users, which, we are told by the Oregon Department of Environmental Quality, will be subject to this proposed rule.

With the unemployment rate hovering around 9.5% nationally and 14% regionally and with talk of a "double dip" recession and/or a "jobless" recovery, every existing job and every projected new job is precious. This is the wrong time to expand these rules that will increase costs for existing and proposed boilers which may impact existing and new job development.

Development of biomass power facilities will provide for increased forest health and lower the potential for catastrophic wildfires on both public and private land. In a state where wildfires are the major contributor to our carbon footprint, the potential to reduce wildfires, generate renewable electricity and create jobs is a win/win for the environment, forest health, business and the public, in general.

Response: See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass.

Commenter Name: Steven D. Swanson
Commenter Affiliation: Swanson Group, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-1874
Comment Excerpt Number: 2

Comment: Our company has, in the past, seriously considered installing new biomass boilers fitted with turbines that can generate clean, "green" power to meet our Nation’s growing demand for renewable energy. Unfortunately, the stringent limits proposed in the Area Source and MACT rule will make projects that are already marginally economical to be that much less so, meaning that in our case, these projects will not occur. This rule will serve to significantly dis-incentivize new biomass power projects, which until now, had been promoted by both State and Federal programs.

We believe that EPA’s goals can and must be reached without the huge regulatory compliance costs that would cripple the industry’s competitiveness and eliminate our economic and environmental contributions. We urge you to reconsider the proposed rule and continue to work with the regulated community to arrive at an effective and workable solution.

Response: The emission limits are revised for the final rule, see the preamble for discussion. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 discussing biomass.

Commenter Name: David Meeker
Commenter Affiliation: National Renderers Association
Document Control Number: EPA-HQ-OAR-2002-0058-1868.1
Comment Excerpt Number: 3

Comment: Also, the Boiler MACT is expected to require installation of up to five different air pollution control devices that will conflict with other existing control requirements. EPA should not ignore the practical capabilities of controls and the variability in operations, fuels, and testing performance across the many regulated sectors.

Response: See the preamble regarding revised emission limits and interactions of control devices.

Commenter Name: Randy Stoeckel
Commenter Affiliation: Johnson Timber Corporation
Document Control Number: EPA-HQ-OAR-2002-0058-1975.1
Comment Excerpt Number: 5

Comment: EPA's proposed Boiler MACT can be crafted in a more balanced way that sustains both the environment and good jobs and doesn't hurt our ability to compete against imported products. If EPA were to provide more flexible approaches in the final Boiler MACT rule and appropriately address the diversity of boilers and fuels in use, it could achieve its goal while preventing severe job losses and billions of dollars in unnecessary regulatory costs. I urge you to consider the cost to American companies for a small reduction in controlled pollutants when our competitors or wildfires dump many times more into the earth's atmosphere every hour. Boiler MACT in its current form is pushing the use of Natural Gas. Is increasing the use of fossil fuels really what is intended?

If the money needed to improve the lower limits on biomass boilers were used to prevent California brush fires how many or how much pollutants would be removed from our air? If we indeed [live on] one planet does it make sense to remove a small amount for a large sum of money when the same amount of money could make a large improvement in other parts of the nation or world?

Response: The emission limits and compliance options are revised for the final rule, see the preamble for discussion. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source.

Commenter Name: Carl Johnson
Commenter Affiliation: Southern Pressure Treaters' Association
Document Control Number: EPA-HQ-OAR-2002-0058-1867.1

Comment Excerpt Number: 8

Comment: If a plant converted to natural gas boilers, the capital investment may not be carried by the market rendering the company non-competitive against imports and alternative products.

If the rules are finalized as written, some utility pole treating plants and supporting operations could be forced into closure resulting in hundreds of unemployed workers and a shortage of utility poles for grid maintenance and new line construction. Restoration of electrical, telecommunication, internet and cable service after natural disasters (i.e. hurricanes, ice storms, etc.) would take longer due to fewer plants operating.

Response: The emission limits are revised for the final rule, see the preamble for discussion. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source.

Commenter Name: Arlington Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1779
Comment Excerpt Number: 27

Comment: The Boiler Rule -– and the identification of non-hazardous materials that are solid waste – the Waste Rule.

As proposed, these two rules threaten to eliminate the longstanding environmentally beneficial practice whereby furniture companies generate heat and process steam at their plants by combusting wood fuel generated from the furniture manufacturing process.

The proposed rules are of great concern to those of us who represent furniture manufacturers and the employees of those companies. Unless altered, the rules could actually have the perverse environmental affect of forcing the transition of furniture manufacturing facilities from the use of wood as a fuel to the combustion of fossil fuels while simultaneously forcing the disposal in the landfills of a clean, high BTU renewable fuel in the form of wood generated from the furniture manufacturing process.

At one facility located in North Carolina we currently estimate that in order to do fuel switching away from the combustion of wood fuel, we estimate an annual cost of $200,000 to dispose of this wood biomass. We also estimate that for that one facility an additional 12,000 tons of wood biomass fuel would be diverted to the landfill.

We also estimate that in order to do fuel switching and move away from wood biomass and switch to natural gas at that one facility with a small Fire tube boiler would cost $1.1 million to fuel switch and continue its operation today.

Response: The solid waste definition pertains to the Identification of Non-Hazardous Materials That Are Solid Waste and it is out of scope for this boiler rulemaking.

Commenter Name: Arlington Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1779
Comment Excerpt Number: 36

Comment: There are unintended consequences of proposing emission standards that would require the installation of control devices that have not been demonstrated to achieve the proposed numeric emission limits and that would, in actuality, increase energy consumption and increase emissions.
There are unintended consequences of requiring the installation of pollution control devices that have not been demonstrated collectively to achieve the standards. For instance, the proposed CO limits for gas-fired units will require operating at much higher oxygen levels than typical, which will lead to increased fuel use and, as a result, increased CO_2 emissions. This is also true for oil-fired units. In fact, emissions of all pollutants other than CO will also increase because of the increased fuel use. Remarkably, the proposal does not indicated how the low CO levels will be achieved. Are we to take this as an indication that EPA's own analysis shows that it's unachievable? TO complicate matters, EPA has also included in this proposed rule precedent-setting energy assessment and ongoing energy management requirements that apply well beyond this source category which, we believe, will further highlight the inconsistency between the low CO levels and the optimum operation of boilers and process heaters.

Response: See the preamble for discussion on CO limits and technical conerns of control devices.

Commenter Name: Arlington Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1779
Comment Excerpt Number: 75

Comment: The rule discourages the use of biomass, and that goes against all of the efforts that Domtar has made to maximize the use of biomass and will likely cause us to reverse some of our –- some of our practices, which will mean an increase in fossil fuel and increase in landfill of materials.

Response: The emission limits are revised for the final rule, see the preamble for discussion. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source.

Commenter Name: Arlington Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1779
Comment Excerpt Number: 83

Comment: The Boiler MACT rules needs to be fixed. The rule, as proposed, will actually discourage industry from using biomass over more traditional fossil fuels or natural gas.

Response: See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source.

Commenter Name: Arlington Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1779
Comment Excerpt Number: 86

Comment: Biomass boilers should be given special consideration. Biomass boilers are carbon neutral and beneficial to the environment. My mill has two biomass boilers. EPA should encourage the continued operation of biomass boilers. By setting unreasonable limits on these biomass boilers, EPA will drive industry toward fossil fuel when EPA should be favoring biomass use.

Response: The carbon emissions from biomass are not within the scope of this rulemaking. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source, and see the preamble for the revised limits.

Commenter Name: Arlington Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1779
Comment Excerpt Number: 93

Comment: There is a need for a real-world assessment of individual emission reductions on the overall boiler systems. Greatly reducing one component of a total emission can be done, but it may cause other emission values to vary.

Response: See preamble for a response to comment on the pollutant-by-pollutant approach.

Commenter Name: Arlington Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1779

Comment Excerpt Number: 116

Comment: Imposing severe and unattainable emission limitations on sources that use or may use locally available alternative fuels such as bio-based fuels, landfill gas, and process off-gases, will decrease the use of alternative fuels and put greater demand on conventional fossil fuel use to the extent that continued operations are justified. These impacts are counter to the stated administration goals of improving national energy efficiency, reducing greenhouse gases, increasing national security, and increasing employment.

Response: See the preamble for discussion of achievability of emission limits, how we adjusted CO levels, and how we modified the gas 1 subcategory to be more inclusive of other fuel types.

Commenter Name: Tyler McShan
Commenter Affiliation: McShan Lumber Company
Document Control Number: EPA-HQ-OAR-2002-0058-2207
Comment Excerpt Number: 1

Comment: People still burn their yards to kill insect pests and just last year the Federal government PAID us to burn thousands of acres of timberland to cut down on the fuel supply and decrease the risk of wild fire. We do some of this every year anyway, last year we just got paid for it.
Our boiler is used to burn sawdust that is generated by sawing lumber. The steam is then used to dry our lumber. The fuel is the same material (pine trees) that we were paid to burn last year. If this fuel was not burned we would have to pay someone to dispose of it and we would have to burn natural gas or fuel oil to dry our lumber.

Response: It is not our desire to preclude operators from burning biomass. The emission limits are revised for the final rule, see the preamble for discussion. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 for further discussion on biomass.

Commenter Name: Thomas Ratzlaff
Commenter Affiliation: City of Park Falls, WI
Document Control Number: EPA-HQ-OAR-2002-0058-2350.1
Comment Excerpt Number: 2

Comment: Our mill uses a lot of biomass in its boilers to run the mill. Biomass is good for the environment because it lets us burn less fossil fuel, reducing our carbon footprint.

Response: See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source.

Commenter Name: Thomas McInvale
Commenter Affiliation: Keadle Lumber Enterprises, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2007.1
Comment Excerpt Number: 2

Comment: It would seem that the Federal Government, with the proposed rules, is abandoning its own push for the increased use of renewable energy and the EPA's recognition and acceptance of the long-standing science behind the carbon neutrality of Biomass emissions.

Response: See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source.

Commenter Name: Kerry Flick
Commenter Affiliation: Metso Power
Document Control Number: EPA-HQ-OAR-2002-0058-2388.1
Comment Excerpt Number: 2

Comment: If the ruling is written into law as proposed, the future of the U.S. biomass renewable energy market will be significantly impacted. Most new plants will not be feasible from a financial perspective given the high costs associated with the integration of needed technologies and equipment. There will be a significant increase in the cost to make power and Utilities will be forced to pass this onto the consumer. Resulting in a much higher price for electricity. Thus, it is believed that the proposed ruling will discourage, if not eliminate, new development of renewable biomass power. We believe that this is not the intent of the current Administration from an energy or economic policy perspective. As a form of renewable energy. biomass energy is CO, neutral hence does not contribute (0 the global green house gas emissions. Furthermore, producing energy form biomass clearly helps our rural economy and energy security.

Response: The emission limits are revised for the final rule, see the preamble for discussion. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source.

Commenter Name: Ardis Almond
Commenter Affiliation: Almond Brothers Lumber Company
Document Control Number: EPA-HQ-OAR-2002-0058-2349.1
Comment Excerpt Number: 2

Comment: We do not have a boiler, but instead we dry our lumber with a direct fired natural gas kiln. As an engineer, I have had a long range plan of converting our drying system from natural gas (a fossil fuel) to a steam kiln with a biomass burning boiler (our own sawdust – a carbon neutral renewable resource). The plan included a co-generation system to produce electricity for our plant and possibly some of the community. We have cancelled all work on that project because of Boiler MACT. This was one of the plans for the future to make us more efficient and help our company survive in a competitive world. Now this won't happen, at least until these restrictive proposals are defeated. Even then, I don't know if I would ever recommend this, when some group at the EPA could shut down a system with few regulations that do not even have to be approved by Congress.

On the one hand, government wants us to use more biomass and at the same time creates regulations that make that impossible. I don't understand it.

Response: The emission limits are revised for the final rule, see the preamble for discussion. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source.

Commenter Name: Troy Runge
Commenter Affiliation: Wisconsin Bioenergy Initiative
Document Control Number: EPA-HQ-OAR-2002-0058-2353.1
Comment Excerpt Number: 2

Comment: The hydrogen chloride (HCl) limit will require many biomass fuel boilers to install scrubbers or inject an alkaline sorbent such as lime. The mercury (Hg) limit would require many boilers to install powdered-activated-carbon-sorbent injection systems, although sufficient data does not exist to know whether activated carbon injection is capable of reducing mercury emissions to the levels required by the new rule. The Carbon Monoxide (CO) and dioxin/furan limits will pose additional challenges for most biomass boiler projects as little emissions testing has been conducted to understand the magnitude of these emissions or how best to control them. Therefore, the stringent emission limits may force new biomass fuel boiler projects either to significantly upgrade their existing pollution-control equipment or consider switching to natural gas. Ultimately, this additional hurdle for the use of biomass will increase the use of fossil fuels, which is counterproductive to President Obama's energy policy and Wisconsin's investment in bionenergy.

We believe the proposed EPA Boiler MACT rule has the following negative unintended consequences:

The rule may severely limit and/or potentially eliminate the use of agricultural biomass fuels, threatening the development of a new local, renewable energy market.

The rule may increase either the facility costs and/or agricultural biomass fuel costs (e.g. fuel may have to be processed to remove minerals) so significantly that these homegrown fuels could not compete with imported fossil fuels like coal or natural gas.

Without agricultural biomass fuels, additional pressure would be put on wood resources (as a substitute for coal), potentially increasing the cost of woody fuels and distorting existing forest products markets, thereby threatening sustainability of harvesting.

Response: The emission limits are revised for the final rule, see the preamble for discussion. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source.

Commenter Name: Don Grimm
Commenter Affiliation: Hood Industries, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2352
Comment Excerpt Number: 4

Comment: If owners or operators of combination boilers anticipate difficulty complying with the proposed CO standard, they may have to switch away from biomass and burn more coal to be able to comply with the coal subcategory emission standards. This unintended consequence of replacing biomass with coal is contrary to national energy and climate policy, which encourages the use of more renewable biomass fuel.

Response: The emission limits are revised for the final rule, see the preamble for discussion. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source.

Commenter Name: John Williams
Commenter Affiliation: Maine Pulp and Paper Association
Document Control Number: EPA-HQ-OAR-2002-0058-1913.1
Comment Excerpt Number: 4

Comment: The limits being considered would necessitate combinations of emission controls that would have adverse effects on each other. For example, the conditions that affect the optimum emissions of CO may run contrary to minimizing emissions of NOx. Although NOx is not address in the Boiler MACT proposal, the northeastern states, including Maine, have focused on the control and reduction of NOx emissions to improve ozone. Another example is the use of activated carbon for mercury control. The presence of sulfur trioxide (SO3) can have a negative impact on carbon injection mercury removal. Small amounts of SO3 are generated during the combustion of sulfur-containing fuels. SO3 interferes with mercury removal by occupying active sites on the carbon.

Response: See the preamble for discussion on revised limits.

Commenter Name: Troy Runge
Commenter Affiliation: Wisconsin Bioenergy Initiative
Document Control Number: EPA-HQ-OAR-2002-0058-2353.1
Comment Excerpt Number: 6

Comment: The proposed MACT rule may disallow whole regions from developing new businesses in renewable biomass energy and encourage the continued use of coal fired boilers which have limits 10 times greater than biomass boilers.

Response: The emission limits are revised for the final rule, see the preamble for discussion. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source.

Commenter Name: Don Grimm
Commenter Affiliation: Hood Industries, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2352
Comment Excerpt Number: 14

Comment: In addition, biomass is a "clean" fuel in many of the same respects as the Gas 1 fuels. Perhaps more importantly, biomass-fired boilers produce no net GHG emissions, which make the combustion of biomass an important tool in managing and reducing the Nation's carbon footprint. Similarly, biomass is an abundant, renewable domestically-produced fuel that can help reduce reliance on foreign sources of fossil fuel and, thus, improve the Nation's energy security. Prescribing stringent HAP emissions limitations on biomass boilers will create a significant barrier to the continued use and expansion of biomass fuels and incentivize the use of less desirable fossil fuel alternatives.

In light of the inordinate costs of complying with the proposed HAP emissions limits for biomass boilers and the strong policy reasons for promoting the combustion of biomass, EPA has ample justification to prescribe work practices rather than HAP emissions limitations for biomass boilers.

Response: The carbon emissions from biomass are not within the scope of this rulemaking. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source, and see the preamble for the revised limits.

Commenter Name: Kevin Bilbrey
Commenter Affiliation: Clarke County Pole and Piling Co, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2414.1
Comment Excerpt Number: 1

Comment: The proposed rules will have a detrimental effect on our company. Our company currently produces untreated wood poles and piling that are primarily utilized by wood preservation companies. After treatment, the wood poles are used primarily by electric utility companies for transmission and distribution of overhead lines to their customers. Treated wood piling is utilized by pile driving companies for foundation support as part of commercial, residential and municipal construction projects. We are currently installing a boiler that will burn wood biomass generated by our on-site pole and piling peeling operations. Steam generated from our boiler will be used a newly constructed on-site dry kiln to remove moisture from the wood poles and pilings prior to being sold to our customers.

Response: The emission limits are revised for the final rule, see the preamble for discussion. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass use.

Commenter Name: Raymond J. Nutting
Commenter Affiliation: County of El Dorado Air Quality Management District
Document Control Number: EPA-HQ-OAR-2002-0058-2713.1
Comment Excerpt Number: 1

Comment: The County of El Dorado has significant and highly productive agricultural and forested land integrated with urban and rural populations producing a wide range of biomass wastes. Although there is currently only one permitted biomass boiler operating in the county, the Board supports programs and plans for new facilities to convert biomass wastes into renewable energy in properly designed, operated, and controlled facilities. Such biomass utilization has shown to provide significant reductions in particulate matter, toxic pollutants, and greenhouse gases as compared with alternative disposal methods of open burning, land filling or in-field degradation.

The AQMD Board is very concerned with the potential consequences of the proposed regulations and does not support the new Maximum Achievable Control Technology (MACT) standards for industrial boilers for major sources and area sources. The proposed boiler MACT standards have not been properly determined and if implemented will result in multiple adverse outcomes. Compliance with this regulation will require existing facilities to install expensive and mostly untested "end of pipe" control technologies, which are not proven necessary to protect human health or environment. Such scenario will almost certainly cause significant increases in local and regional levels of particulate matter, toxic pollutants and greenhouse gases since unmanaged biomass wastes will be consumed by wildfires, through prescribed burning or be land filled. It will be necessary to burn more fossil fuel to accommodate for lost biomass energy.

Response: The emission limits are revised for the final rule, see the preamble for discussion. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source.

Commenter Name: Charles R. Faulds
Commenter Affiliation: Texas Electric Cooperatives, Treating Division
Document Control Number: EPA-HQ-OAR-2002-0058-2526.1
Comment Excerpt Number: 1

Comment: Advantages of utilizing biomass will diminish under the EPA proposed rules at the same time other departments of the government are encouraging and even subsidizing biomass facilities.

Response: The emission limits are revised for the final rule, see the preamble for discussion. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source.

Commenter Name: Joe O'Rourke
Commenter Affiliation: F.H. Stoltze Land and Lumber Co
Document Control Number: EPA-HQ-OAR-2002-0058-2418.1
Comment Excerpt Number: 1

Comment: These proposed rules will have a significant, detrimental impact on our company and on our employees.

We are a family-owned sawmill located in Columbia Falls, MT. We produce up to 70,000,000 boardfeet of lumber per year. We have been in business in the same location since 1923. We employ 117 people.

We have a bank of four boilers that are now 100 years old. Those boilers burn woody residues that are a byproduct of sawmill lumber production. We are currently examining replacing these old boilers with a newer boiler system that would also be capable of power generation. The cogeneration boiler would produce both process heat for our lumber drying operations, as well as generating electrical power that would be sold as renewal, carbon-neutral (green) energy to the power grid.

The EPA proposed rules referenced above would not only make our goal of generating a combination of process heat and green power from a renewable resource, much more difficult, it would threaten the very existence of our business and the jobs of our employees.

Response: The emission limits are revised for the final rule, see the preamble for discussion. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source.

Commenter Name: Jon Geenen
Commenter Affiliation: United Steelworkers

Document Control Number: EPA-HQ-OAR-2002-0058-2707.1
Comment Excerpt Number: 1

Comment: If the rules go into effect as written they will create a huge incentive to every industrial user of renewable biomass to switch to natural gas, contrary to the intent of Congress and contrary to the stated policy of the current administration.

Response: The emission limits are revised for the final rule, see the preamble for discussion. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source.

Commenter Name: Claude Audet
Commenter Affiliation: Boralex, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2387.1
Comment Excerpt Number: 2

Comment: Boralex contributes significantly to improving the environment by utilizing wood residues generated at saw mills, pulp mills and large bark piles that, in the past, posed substantial environmental threat to ground and surface water and posed risk of fire through spontaneous combustion. Trees targeted for harvesting are done so in a sustainable manner. The saw logs and pulp wood are removed for market with only the tree limbs and branches remaining. The branches and limbs are chipped, purchased by Boralex and used as a part of the biomass fuel source at its facilities. This biomass is waste wood it is NOT the trunk portion of the tree that has marketable opportunities. Combustion occurs under controlled conditions and emissions are reduced using control devices which, at a minimum, meet EPA's Best Available Control Technology (BACT) criteria. When the biomass is combusted under controlled conditions in our boiler furnaces, no additional CO_2 impacts occur.
Conversely, letting these wood residues decompose in the forest will cause greenhouse gases such as methane, a greenhouse gas that is 25 times more potent than CO_2 to be emitted directly into the air. It also takes time for the decomposition process to occur. During that time, the limbs and branches cover the forest floor, significantly slowing forest regeneration. Forest fires are also known to occur as a result of poor forest management practices. Forest fires often result in tremendous amounts of combustion by¬products being released uncontrollably into the atmosphere. Significant environmental, societal and economical impacts often result, such as wildlife habitat destruction and surface and ground water pollution, all of which can take many years to recover. The threat of loss of life from an uncontrolled forest fire is always present and, economic losses are often staggering.
Combustion of biomass for energy production makes sense. Biomass displaces fossil fuels (a significant climate change benefit) and moves our nation closer to energy independence, a goal that we should all share and do our utmost to obtain.

Response: See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source.

Commenter Name: Jack Carter
Commenter Affiliation: Weyerhaeuser Company
Document Control Number: EPA-HQ-OAR-2002-0058-2797.1
Comment Excerpt Number: 2

Comment: We are concerned with how biomass is treated as a fuel category, which touches on the MACT floor/technical feasibility issues discussed above and on many of the issues noted in our Specific Comments section that follows. Because Weyerhaeuser is a major grower and provider of timber and manufacturer of wood and pulp/paper products, we have a significant interest both in the markets for the primary timber resources and secondary materials that end up as biofuels or biomass fuels. As on-site energy producers and consumers, most of our mills use significant quantities of biomass for fuel in its various forms and from a variety of sources. While some amount of fossil fuels are used at most mills and some smaller mills use only fossil fuels, most of our mills primarily use biomass to fuel their boilers and process heaters. In fact, using 2009 data as a snapshot, among our five U.S. pulp mills the median biomass-sourced fuel energy consumed for on-site energy production was 91% of the total on-site fuel energy consumed. For our major and area source wood products mills in the U.S. that utilize biomass fuels, the median biomass fuel energy was 85% of the total on-site fuel energy consumed. Btu basis, estimated from all biomass fuels used to fire on-site boilers and process heaters during 2009. For pulp mills this includes recovery furnaces combusting the biomass contained in the recycled pulping liquors. Our mills also marketed some 4800 billion BTUs in biomass residuals fuels energy to third parties in 2009. And although we do not have a specific estimate, we expect an even larger additional amount of biomass fuel is derived from our timber and forest residuals sales to third parties. Use of these renewable biomass fuels supports the Nation's goals to reduce dependence on foreign energy sources, reduce the greenhouse gas footprint of energy production, and to incent the long-term keeping of working forest lands as forest. The AWC and AF&PA comments go into more detail on the Forest Products Industry significant use of biomass to self-satisfy energy needs and the NAFO comments address the growing use and importance of this renewable resource nationwide. For example, the AWC and AF&PA comments identify that there are over 800 boilers and process heaters at wood products facilities in the U.S. and the majority of these boilers burn biomass.
Unfortunately, EPA creates a set of disincentives for biomass use because of how the proposed emission limits have been set and because of problems with EPA's use of the emissions data for several of the HAPs.

Response: The emission limits are revised for the final rule, see the preamble for discussion. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source.

Commenter Name: Jay Galloway
Commenter Affiliation: Tolleson Lumber Company
Document Control Number: EPA-HQ-OAR-2002-0058-2452.1

Comment Excerpt Number: 3

Comment: Ironically, the proposed rule will drive companies to switch from burning renewable biomass to burning nonrenewable fossil fuel (natural gas) – the very opposite to protecting the environment!

Response: EPA recognizes that the situation of each affected entity is different, and although some facilities may opt to switch to natural gas in lieu of biomass combustion, the data show that many biomass facilities are at or below the final emission limits. This suggests that many facilities will adopt biomass fuel specifications or install controls in order to meet the emission limits. Furthermore, EPA has determined that changes from the proposal have reduced economic impact on many biomass facilities; see the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 for further discussion on biomass.

Commenter Name: James P. Brooks
Commenter Affiliation: Maine Department of Environmental Protection, Bureau of Air Quality
Document Control Number: EPA-HQ-OAR-2002-0058-2746.1
Comment Excerpt Number: 4

Comment: Reducing CO is likely to increase NOx, or will create the need for additional NOx control. This is contrary to other air quality efforts to address regional haze and interstate transport. Many Maine facilities have installed SNCR or low NOx burners to meet current NOx standards. The Maine DEP is concerned that the effort and expense necessary for many facilities to comply with the proposed standards will have little real impact on the pollutants of concern that EPA is directed to address in Section 112 of the Clean Air Act.

Response: See the preamble for discussion on CO limits.

Commenter Name: Arthur N. Marin
Commenter Affiliation: NESCAUM
Document Control Number: EPA-HQ-OAR-2002-0058-2893.1
Comment Excerpt Number: 4

Comment: NOx reduction strategies for ozone reduction may be negated if CO limits for HAPs are too low. For example, lime kilns have experienced exceptionally high NOx values (1100 ppm NOx) resulting from CO controls. [See submittal for graphical example of this tradeoff, which is a plot of annual NOx vs. CO emission rates (lb/mmBtu) obtained from stack tests at a paper mill waste fuel incinerator.]

Response: See the preamble for discussion on CO limits.

Commenter Name: Robert Ellerhorst
Commenter Affiliation: Michigan State University
Document Control Number: EPA-HQ-OAR-2002-0058-2816.1
Comment Excerpt Number: 4

Comment: Maximizing combustion efficiency must be balanced with the potential increase of nitrogen oxide (NO.) emissions that could occur when combustion efficiency is associated with high chamber temperatures. Maintaining reduced NO levels is of particular concern to MSU in order to comply with current air use permit limits for NO as well as Clean Air Interstate Rule (CAIR) ozone season requirements.

Response: See preamble for discussion on relationshipo between CO and NOx emissions.

Commenter Name: Kevin Bilbrey
Commenter Affiliation: Clarke County Pole and Piling Co, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2414.1
Comment Excerpt Number: 4

Comment: This is absurd given the fact that wood biomass is greenhouse-gas neutral and the government continues to encourage the increased use of biomass as a renewable energy. Wood biomass produces no net addition of CO_2 since the CO_2 emitted is equal to the CO_2 removed from the atmosphere in the creation of wood fiber.

Response: The carbon emissions from biomass are not within the scope of this rulemaking. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source.

Commenter Name: Robert Klemans
Commenter Affiliation: Florida Electric Power Coordinating Group Environmental Committee
Document Control Number: EPA-HQ-OAR-2002-0058-2733.1
Comment Excerpt Number: 6

Comment: EPA HAP Regulation of Biomass. FCG believes that renewable fuels should be considered as part of a diverse energy supply portfolio, and our members are pursuing options, such as biomass, that can help us continue to provide reliable and affordable energy to our customers.

Economic renewable energy resources are unevenly distributed across the United States and the Southeast. Currently, one of Florida’s most promising economic renewable resources is biomass. Most renewable resources provide an intermittent supply of energy, but biomass generation is capable of producing a reliable supply of baseload energy, making it extremely beneficial.

However, the stringent limits and requirements in the proposed IB MACT decrease the prospect of producing reliable renewable energy from biomass. Florida needs the capability of producing renewable energy from biomass. FCG believes the proposed stringent emission limits within the proposed IB MACT may hinder the technologic and economic drivers for new and biomass conversion projects in Florida.

EPA should encourage the combustion of biomass as substitute fuel for coal or oil as a matter of good public policy. The combustion of biomass will become increasingly important to utilities if renewable energy standards are adopted by more states and are possibly applied to all states as a result of federal mandates. Biomass is an abundant and renewable domestically-produced fuel that can help reduce reliance on foreign sources of fossil fuel. Prescribing stringent HAP emissions limitations on biomass boilers will create a significant barrier to the continued use and expansion of biomass fuels.

Response: See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source.

Commenter Name: Tim Keneally
Commenter Affiliation: KapStone Paper and Packaging Corporation
Document Control Number: EPA-HQ-OAR-2002-0058-2673.1
Comment Excerpt Number: 9

Comment: EPA should understand that KapStone may have to switch away from biomass and burn more coal to be able to comply with the coal subcategory emission standards. This unintended consequence of replacing biomass with coal is contrary to national energy and climate policy, which encourages the use of more renewable biomass fuel.

Response: See the preamble for revised emission limits.

Commenter Name: Britt S. Fleming
Commenter Affiliation: Auto Group
Document Control Number: EPA-HQ-OAR-2002-0058-2775.1
Comment Excerpt Number: 9

Comment: Section 112(h) Work Practices for Natural Gas-Fired Boilers Over 10 mmBtu/hr Are Appropriate as a Matter of Policy.

The application of work practices to natural gas-fired boilers/process heaters also is justified as a matter of public policy. As EPA notes in the preamble, requiring natural gas-fired boilers and process heaters to install costly add-on controls may create a disincentive for switching to natural gas. The proposed work practices approach for natural gas boilers/process heaters eliminates the disincentive that would be created by stringent emissions limits that penalize the low-HAP emissions of this fuel. As noted earlier in these comments and as demonstrated by EPA's database for this rulemaking, natural gas-fired boilers and process heaters have some of the lowest HAP emissions and therefore pose very low risk. Consequently, many auto facilities already have expended large amounts of capital switching to natural gas as a means to minimize regulatory concerns.

For example, a number of facilities have converted coal-fired boilers to burn natural gas (with some having fuel oil back-up and/or ability to burn landfill gas as well) over the last couple decades, which has helped areas comply with new, more stringent National Ambient Air Quality Standards (NAAQS). For those facilities that have not converted, stringent emission limits that necessitate costly add-on controls will serve to discourage further conversions to lower HAP fuels. Specifically, if both coal-fired boilers and natural gas-fired boilers are subject to stringent emission limits and require costly add-on controls for purposes of complying with the limits, coal will be more attractive given the historically low price of that fuel. Furthermore, add-on controls will decrease boiler efficiency and increase fuel consumption. These are "absurd results" that run contrary to EPA's efforts to encourage industry to increase energy efficiency and move to cleaner, lower-polluting fuels. These policy considerations further bolster EPA's decision to impose work practices on larger natural gas-fired boilers and process heaters.

Response: Natural gas boilers do not have emission limits but must follow work practice standards.

Commenter Name: Myra C. Reece
Commenter Affiliation: South Carolina Department of Health and Environmental Control
Document Control Number: EPA-HQ-OAR-2002-0058-2525.1
Comment Excerpt Number: 25

Comment: Wwe believe that EPA should take into consideration how this rule could affect the emissions of non-HAP pollutants and whether the rule produces the greatest overall air quality and public health improvement. For example, the proposed Boiler MACT requirements for carbon monoxide (CO) may cause increases in greenhouse gas and nitrogen oxide (NOx) emissions. The EPA's current approach to regulating air emissions does not prioritize pollutants for comprehensive air quality management and in some cases may exacerbate air quality issues.

Response: See the preamble for response regarding CO emission limits and their impacts on other pollutants.

Commenter Name: Jack Carter
Commenter Affiliation: Weyerhaeuser Company
Document Control Number: EPA-HQ-OAR-2002-0058-2797.1
Comment Excerpt Number: 26

Comment: To meet the proposed Boiler MACT limits may require controls in some circumstances, such as wet scrubbers, that will come into conflict with the effluent guidelines for wood products mills that prohibit discharge of process wastewaters. Certain air pollution control devices that generate process wastewater have previously been exempted from this effluent guideline when used at facilities also covered by the Plywood and Composite Wood Products (PCWP) MACT Rule (subpart DDDD). 40 CFR Part 429, the Timber Products Processing Point Source Category states that "there shall be no discharge of process wastewater pollutants into navigable waters" for facilities covered under subparts B, C, D and M (dry process hardboard, veneer, finishing, particleboard, sawmills and planing mills). In conjunction with the PCWP rule, these subparts were narrowly modified to allow discharge from air pollution control devices (APCD) associated with controlling HAP emissions covered by PCWP. However, mills in the wood products industry subject to Part 429 cannot legally discharge wet scrubber or other wet control device blowdown that are installed to comply with the Boiler MACT because they constitute process wastewaters. Scrubbers and wet electrostatic precipitators may be required by some wood product industry boilers subject to Part 429 in order to comply with these air standards. If EPA chooses to insist on compliance with numerical emissions limits in this situation, then the effluent guidelines definition of "process wastewater" in 40 CFR §429.11(c) must be amended to exclude wastewater from air pollution control devices on boilers and process heaters complying with the major source or the area source NESHAP. We refer EPA to the AWC comments on this issue, which provide more detailed descriptions of the APCD wastewater volumes and other relevant information to support a similar recommendation.

Response: See the preamble for discussion regarding wastewater discharge and biomass boilers.

Commenter Name: Stephen R. Gossett
Commenter Affiliation: Eastman Chemical Company
Document Control Number: EPA-HQ-OAR-2002-0058-3137.1
Comment Excerpt Number: 29

Comment: Compliance with the standards for Gas 2 is expected to be cost prohibitive (see more discussion on cost below) and is expected to result in a net increase in emissions as well as increase the use of fossil fuel.

Response: See the preamble for discussion of achievability of emission limits, how we adjusted CO levels, and how we modified the gas 1 subcategory to be more inclusive of other fuel types.

Commenter Name: Stephen R. Gossett
Commenter Affiliation: Eastman Chemical Company
Document Control Number: EPA-HQ-OAR-2002-0058-3137.1
Comment Excerpt Number: 33

Comment: When faced with a decision to comply with the proposed rule for Gas 2 units, sources will have one of three basic options: (1) install the high cost controls EPA describes on page 32025 of the
proposed rule that would be needed for Gas 1 units – fabric filter, a wet scrubber, and an oxidation catalyst system, (2) flare (or install a thermal oxidizer) the process gas (and burn additional natural gas to make up for the lost heating value, and (3) install a new boiler just for the process gas. Any of these three options will be very costly. When faced with the difficulties of retrofitting existing boilers with air pollution control systems never envisioned (i.e. no space or structure available) or the expense and permitting difficulties of installing a new unit (not to mention the challenges of finding equipment that would meet the proposed new unit emission standards), we believe many facilities would opt for the flaring option.

At one of Eastman's facilities, we have estimated increased natural gas costs of $5M per year to replace lost heating value from just one process gas system that currently is burned in six existing gas-fired boilers. At one of our facilities, we operate three ethylene plants, each of which is highly integrated and burns its own process gas (primarily hydrogen and methane – no HAPs) for energy recovery in the ethylene plants' cracking furnaces and waste heat boilers. Natural gas is supplied to provide additional fuel as needed for these combustion units. While the cracking furnaces would be exempted from the Boiler and Process Heater MACT per proposed §63.7491(f) , the six waste heat boilers would be subject to the Gas 2 subcategorical standards. While we have no stack test or CEMS data on these units to judge their performance, we doubt these units could comply with the proposed CO standard. Due to anticipated prohibitive costs to install air pollution control devices such as fabric filters and oxidation catalyst systems, Eastman would likely decide to flare this process gas and replace it with natural gas at an estimated annual cost of $3.5 M. The increased VOC emissions from flares (less efficient than boilers) and the increased NOx emissions from the flaring, while legal, would be an unfortunate outcome of compliance with the proposed rule.

Response: See the preamble for discussion of achievability of emission limits, how we adjusted CO levels, and how we modified the gas 1 subcategory to be more inclusive of other fuel types.

Commenter Name: Britt S. Fleming
Commenter Affiliation: Auto Group
Document Control Number: EPA-HQ-OAR-2002-0058-2775.1
Comment Excerpt Number: 35

Comment: The proposed unachievable emission limits applicable to landfill gas units are in direct conflict with programs EPA has put in place to promote the advantageous use of this fuel. EPA established the Landfill Methane Outreach Program (LMOP) in 1994, which, according to EPA's website, is a voluntary assistance and partnership program that encourages the use of landfill gas as a renewable, green energy source. [Footnote: See http://www.epa.gov/lmop/basic-info/index.html (emphasis added).] EPA's website explains that the agency "launched LMOP to encourage productive use of [landfill gas] as part of the United States' commitment to reduce GHG emissions under the United Nations Framework Convention on Climate Change."

[Footnote: See http://www.epa.gov/lmop/basic-info/index.html (emphasis added).] By preventing emissions of methane through the development of landfill gas energy projects, LMOP strives to assist businesses, states, energy providers, and communities in protecting the environment and building a sustainable future. [Footnote: See http://www.epa.gov/lmop/basic-info/index.html (emphasis added).] EPA notes on its website that there are 519 operational landfill gas energy projects in the U.S. EPA also estimates that approximately 530 other landfills are good candidates for projects to turn their gas into energy. [Footnote: See http://www.epa.gov/lmop/basic-info/index.html (emphasis added).]

As EPA describes on its website, landfill gas is extracted from municipal solid waste landfills and then collected where it is processed and treated for further use. [Footnote: See http://www.epa.gov/lmop/basic-info/index.html (emphasis added).] Depending on the design, up to 60-90% of the methane emitted from a landfill is captured by a landfill gas energy project thereby significantly reducing a potent GHG. [Footnote: EPA explains on its website that "methane is a very potent greenhouse gas that is a key contributor to global climate change (over 21 times stronger than CO_2). Methane also has a short (10-year) atmospheric life. Because methane is both potent and short-lived, reducing methane emissions from MSW landfills is one of the best ways to achieve a near-term beneficial impact in mitigating global climate change." Id.] According to EPA's website and recent presentation materials from EPA, landfill gas can be used to generate electricity and is currently powering close to 1 million homes (supplying 13 billion kilowatt-hours). Landfill gas also can replace fossil fuels in industrial and manufacturing operations or can be upgraded to pipeline-quality gas where the gas may be used directly or processed into an alternative vehicle fuel. [Footnote: See http://www.kdheks.gov/waste/workshops/works10/presentations/hamburg-EPALMOPsuccessstories-2010.pdf] In fact, according to the DTE Biomass Energy's website, landfill gas is processed to a degree that it is of natural gas quality and can be injected directly into the natural gas pipeline distribution system for use by consumers. [Footnote: See http://www.dtebe.com/services/pipelineGas.html.]

In light of the importance of encouraging the use of landfill gas as a renewable green energy fuel as evidenced by EPA's LMOP efforts and projects, the Auto Group urges EPA to impose work practice standards on landfill gas boilers/process heaters at major sources instead of emission limits. As explained above, landfill gas is an important energy resource and EPA should promote the continued use of this fuel rather than prevent boilers/process heaters from combusting landfill gas because these units are incapable of meeting the proposed emission limits (or some other emission limit that EPA believes represents the average of the best performing 12%). Furthermore, the use of landfill gas reduces the GHG load and offsets the use of other fossil fuels, which are higher in HAP emissions and are non-renewable. Penalizing major sources using landfill gas-fired boilers/process heaters by imposing an unachievable emission limit does not make sense from a policy perspective.

If finalized as proposed, the emission limits applicable to landfill gas units will have the result of severely restricting the future use of landfill gas and could, in all likelihood, lead to this beneficial fuel being once again flared or routed to other devices that may not be as efficient in combusting landfill gas or as effective in reducing other potential emissions (e.g., GHGs) as the boilers/process heaters currently being used. It is important to utilize the energy that landfill gas can provide and reduce the GHG load associated with the use and dependence on other fossil fuels. For these reasons, EPA should impose work practice standards on landfill gas units similar to what is being proposed for natural gas and refinery gas units.

Response: See the preamble for new subcategory definitions and discussion of CO limits.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 171

Comment: Large integrated chemical plant sites strive to be as energy efficient as possible. One way to promote energy efficiency is to capture off-gas from petrochemical and chemical plant off-gas streams and re-use these streams as fuel in a variety of combustion sources. Plant sites are designed to use many types of “gas 2” streams as a fuel in order to have energy efficient operations. If gas 2 fuels are subjected to stringent emission limits instead of work practice requirements, the rule likely will force facilities to dispose of process off-gases in other types of combustion sources including flares, which results in more natural gas being used, inefficient operations, and an increase in greenhouse gas emissions.

Response: See the preamble for discussion of achievability of emission limits, how we adjusted CO levels, and how we modified the gas 1 subcategory to be more inclusive of other fuel types.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 187

Comment: Most boilers are designed to mix fuel and air at an appropriate ratio, and to provide sufficient residence time for the fuel to combust completely. Obviously, these factors are fuel-dependent, as a gaseous fuel will require less time for complete combustion than a liquid fuel, which in turn requires less time to burn than a solid fuel. The need for longer residence time is why the radiant sections in solid-fuel fired boilers are larger than for gas-fired units. The size of the boiler is typically optimized to allow for complete combustion, while minimizing the cost of construction materials. If the construction cost were not a concern, a new boiler could be designed with additional residence time to complete the combustion process and minimize CO emissions.
Unfortunately, increasing the size of the furnace is not an option for existing units. For these units, the strategy for reducing CO emissions is typically to raise the level of excess oxygen. The increase in oxygen concentration has two positive effects. First, it acts to overcome poor distribution of the fuel. Second, it increases the flame temperature, which speeds up the combustion reactions, allowing more complete combustion to occur for the same residence time.

However, there are also a number of negative impacts associated with operating a boiler at higher levels of excess oxygen. The residence time of combustion gases in the furnace decreases, resulting in less time for complete burnout of intermediates such as CO. Many boilers do not have sufficient fan capacity to run with elevated excess oxygen at the high end of the load range. Therefore, these units would effectively be derated by such a strategy. A site might have to add another boiler to offset the reduction in steam generating capacity. If the excess oxygen is increased to very high levels, CO and hydrocarbon emissions will increase and flame stability is impaired, mainly because this leads to a cooler flame.

The minimization of excess oxygen in boiler applications is a key feature for maximizing boiler efficiency. For a given fuel, the boiler efficiency is defined by the amount of combustion air that is used, and the difference between the ambient temperature and the stack exhaust temperature. The more air that is heated up through the combustion process, the more heat is lost to the atmosphere, causing the boiler to be less efficient. A less efficient boiler will require more fuel to be fired to produce a given amount of steam. The additional fuel firing results in higher operating costs, and higher greenhouse gas emissions.

Minimizing the level of excess oxygen is also a primary strategy for reducing NOx emissions from a boiler. The NOx formation mechanisms are dependent upon the temperatures in the flame zone, and the stoichiometry of the fuel and oxygen introduced into the furnace. Reducing the level of excess oxygen reduces the peak flame temperature, which reduces the rate at which the nitrogen in the air dissociates. As such, there is less monatomic nitrogen available to be oxidized to form ‘thermal NOx’. Similarly, if there is less oxygen present, the monatomic nitrogen is less likely to be oxidized (and more likely to react with a second monatomic nitrogen to form diatomic nitrogen). This reduces both the amount of thermal NOx, and the ‘fuel NOx’ (NOx that is formed by the release of fuel-bound nitrogen). Therefore, increasing the level of excess oxygen will result in higher NOx emissions.

Response: See the preamble for discussion on CO limits.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 269

Comment: The effluent limitations guidelines for the Timber Products Processing Point Source Category in 40 CFR part 429 subparts B (Veneer subcategory), C (Plywood subcategory), D (Dry Process Hardboard subcategory), and M (Particleboard Manufacturing subcategory) prohibit the discharge of process wastewater pollutants. “Process wastewater” is defined quite broadly, with only a few exclusions. See 40 C.F.R. § 429.11(c). Facilities within these source categories would be prohibited from discharging the blowdown from a wet scrubber installed on a boiler or CISWI unit. Additionally, numerous other types of facilities that manufacture structural and engineered wood panels that are not covered by the cited effluent guidelines (such as medium density fiberboard) have NPDES permits that prohibit the discharge of process wastewater pollutants, based on a Best Professional Judgment determination that extrapolates from the effluent guidelines.

For these types of facilities, installing any scrubber or a wet electrostatic precipitator to meet new HCl or PM limits may not be practicable. Many mills subject to a zero-discharge requirement already must go to great lengths to manage the wastewater they already generate, and they would be unable to accommodate any additional generation of substantial amounts of wastewater. Many of these facilities are in rural areas where public sewer systems are unavailable, and if they cannot discharge their wastewater pursuant to an NPDES permit they have no feasible means for disposing of it. (In some cases, it might be theoretically possible to truck the wastewater to a commercial wastewater treatment facility or publicly owned treatment plant, but the cost would be prohibitive.)

Response: See the response to comment EPA-HQ-OAR-2002-0058-2797.1, excerpt 26.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 272

Comment: While we believe that a work practice standard would be the best way to deal with the range of circumstances that might be presented at wood products facilities, if EPA insists on settling numerical limits on HCl and other pollutants that could require the installation of wet air pollution control devices, EPA should further modify the definition of "process wastewater" in 40 C.F.R. § 429.11(c) to exclude "wastewater from air pollution control devices on boilers and process heaters … for Industrial, Commercial, and Institutional Boilers and Process Heaters at major source facilities (40 CFR 63 Subpart DDDDD) and for Industrial, Commercial, and Institutional Boilers at area sources (40 CFR 63 Subpart JJJJJJ)." As is currently done for wastewater from air pollution control devices installed to meet the Plywood and Composite Wood Products NESHAPs, the excluded wastewaters would be subject to effluent limitations developed by the permit writer on a Best Professional Judgment basis. See 69 Fed. Reg. at 45,965.

Response: See the response to comment EPA-HQ-OAR-2002-0058-2797.1, excerpt 26.

Commenter Name: Ronald W. Gore
Commenter Affiliation: Alabama Department of Environmental Management
Document Control Number: EPA-HQ-OAR-2002-0058-2465.1
Comment Excerpt Number: 1

Comment: The proposed rules impose severe emission restrictions on the combustion of biomass. Since many facilities may not be able to afford the controls required to meet the proposed MACT limitations, it appears that the proposed rules will drive these facilities towards the combustion of natural gas to meet energy requirements. Since biomass is a renewable source of energy, this appears to run contrary to the current Administration's stated desire to move away from fossil fuels and towards renewable sources of energy.

Alabama, along with other States, is facing mandatory renewable energy targets in the future. For obvious reasons, wind, solar, geothermal, and many other renewable sources are not viable in Alabama. Biomass appears to be the primary alternative. Our State may not be able to meet its goals if biomass usage is discouraged.

Response: The emission limits are revised for the final rule, see the preamble for discussion. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source.

Commenter Name: Ronald W. Gore
Commenter Affiliation: Alabama Department of Environmental Management
Document Control Number: EPA-HQ-OAR-2002-0058-2465.1
Comment Excerpt Number: 2

Comment: Given the current Administration's desire to regulate Greenhouse Gas emissions, it is perplexing to the Department that the EPA would drive facilities away from utilizing what may be considered a 'carbon neutral' fuel. Furthermore, when combined with the recently proposed solid waste definition, it appears that the fate of wood residuals may be landfills, where it will decay into methane, which has a CO_2 equivalence of 25:1.

Response: The carbon emissions from biomass are not within the scope of this rulemaking. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source, and see the preamble for the revised limits. Also, the solid waste definition pertains to the Identification of Non-Hazardous Materials That Are Solid Waste and it is out of scope for this boiler rulemaking.

Commenter Name: Paul Mikesell
Commenter Affiliation: Cytec Industries Inc.
Document Control Number: EPA-HQ-OAR-2002-0058-2736.1
Comment Excerpt Number: 3

Comment: The proposed regulation creates, what would be assumed as, unintended consequences for using Landfill Gas as a fuel source, where stringent emissions limits will be applicable, stack testing will be required, CEMS / COMS installation and operating requirements may be applicable, and additional record keeping requirements, as well as the additional costs of compliance will be realized. The proposed regulation would drive up the cost for continued development of Landfill gas as a fuel source, force the site to revert back to Natural Gas, and future landfill gas utilization projects would be abandoned. As proposed, this regulation presents a negative connotation from EPA that Landfill Gas, used as a source of fuel, has no benefit to the environment and should receive no regulatory amnesty similar to natural gas or refinery gas.

Response: See the preamble for discussion of achievability of emission limits and how we modified the gas 1 subcategory to be more inclusive of other fuel types.

Commenter Name: David Roosevelt
Commenter Affiliation: Cabazon Band of Mission Indians
Document Control Number: EPA-HQ-OAR-2002-0058-2676.1
Comment Excerpt Number: 4

Comment: Biomass power has long served as an important and reliable alternative source of electricity. It is a pillar of long-standing renewable portfolio standards adopted in many states, especially in California. Looking forward, biomass is included as one of the renewable technologies eligible for the Renewable Energy Standards proposed in several bills before this Congress. Indeed, according to the Congressional Research Service, biomass power represents over half of the total renewable energy generation in the United States.

Biomass power plants nationwide divert millions of tons of material that otherwise would have been disposed of through more polluting methods such as landfilling or open burning. The use of woody biomass and agricultural residues as fuel in biomass boilers dramatically reduces the emissions of particulate matter, carbon monoxide, and nitrogen oxides that would be byproducts of open burning. In addition, biomass material derived from forest management activities provides further emissions benefits by reducing the risk of wildfire and improving forest health. More specifically, the Colmac plant on the Tribe's reservation diverts over 1,000 tons per day of wood wastes that would otherwise be deposited in landfills to biodegrade, burned in the open fields, or. left on the forest floor to rot or eventually burn in either a prescribed burn or in a wildfire.

Response: See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source.

Commenter Name: Mary Graham
Commenter Affiliation: Charleston Metro Chamber of Commerce
Document Control Number: EPA-HQ-OAR-2002-0058-2732.1
Comment Excerpt Number: 5

Comment: EPA should understand that owners or operators of combination boilers that anticipate difficulty complying with the proposed CO standard, may have to switch away from biomass and burn more coal to be able to comply with the coal subcategory emission standards. This unintended consequence of replacing biomass with coal is contrary to national energy and climate policy, which encourages the use of more renewable biomass fuel.

Response: The emission limits are revised for the final rule, see the preamble for discussion. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source.

Commenter Name: Arnold Schwarzenegger
Commenter Affiliation: Governor Arnold Schwarzenegger
Document Control Number: EPA-HQ-OAR-2002-0058-2697.1
Comment Excerpt Number: 7

Comment: If implemented as proposed, the MACT regulations will have a significant impact on the ability of biomass-to-energy facilities to continue to operate in the State and the State's ability to meet its 33 percent renewable energy goals by 2020.

Development of biomass as an energy source is very important to the State of California. The State, through Governor Schwarzenegger's Executive Order S-06-06, establishes a 20 percent target for biomass within its established State goals for renewable generation for 2010 and 2020. Currently, generation from biopower resources provides about 20 percent of California's renewable energy or an estimated 2.8 percent of California's total in-state power generation.

Response: The emission limits are revised for the final rule, see the preamble for discussion. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source.

Commenter Name: Arnold Schwarzenegger
Commenter Affiliation: Governor Arnold Schwarzenegger
Document Control Number: EPA-HQ-OAR-2002-0058-2697.1
Comment Excerpt Number: 9

Comment: The California Air Resources Board indicates that the proposed rule will not necessarily improve the air quality, and we agree that it will have unintended consequences. Specifically, the Bioenergy Interagency Working Group believes the proposed rule will have negative environmental impacts by increasing the amount of opening burning of agricultural and forest waste, there will be higher risks of wildfires, and more greenhouse gas from landfills.

Continued operation of the biomass-to-energy facilities supports state and federal healthy forest initiatives, helps our agricultural sector, assists solid waste disposal, and enables utilities to meet renewable energy mandates.

Response: The emission limits are revised for the final rule, see the preamble for discussion. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source.

Commenter Name: David A. Buff
Commenter Affiliation: Golder Associates Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2801.1
Comment Excerpt Number: 11

Comment: to comply with the coal subcategory emission standards. This unintended consequence of replacing biomass with coal is contrary to national energy and climate policy, which encourages the use of more renewable biomass fuel.

Response: The emission limits are revised for the final rule, see the preamble for discussion. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source.

Commenter Name: Robert D. Morrison
Commenter Affiliation: Abbott Laboratories
Document Control Number: EPA-HQ-OAR-2002-0058-2764.1
Comment Excerpt Number: 13

Comment: Combustion of LFG has several desirable environmental benefits, including use of a renewable fuel and capture of useful thermal energy that would otherwise be wasted by combustion in a flare. The stringent and unreasonable limits proposed by EPA will have a chilling effect on the use of LFG in boilers and the environmental benefits associated with LFG will be lost. Accordingly, USEPA must conduct a more detailed analysis of LFG combustion in order to provide an informed determination of reasonable MACT that will not prevent its combustion in boilers.

Response: See the preamble for discussion of achievability of emission limits and how we modified the gas 1 subcategory to be more inclusive of other fuel types.

Commenter Name: William R. Ermatinger
Commenter Affiliation: Northrop Grumman
Document Control Number: EPA-HQ-OAR-2002-0058-2506.1
Comment Excerpt Number: 15

Comment: If excess air is increased to ensure complete fuel burning and thus minimize CO emissions to meet the Boiler MACT emission limit for CO, the additional supplied air is unnecessarily heated, which wastes additional fuel as the hot air is discharged to atmosphere.

This heat loss to atmosphere significantly reduces operating efficiency, requiring the combustion of even greater amounts of fuel to compensate for the lost heat that is not available to produce steam.

Response: See the preamble for discussion on CO limits.

Commenter Name: David A. Buff
Commenter Affiliation: Golder Associates Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2801.1
Comment Excerpt Number: 29

Comment: It is noted that lowering CO increases nitrogen oxides (NOx) emissions, i.e., the lower the CO limit is set, the higher the NOx emissions will be. This will be contrary to federal, state, and local programs aimed at reducing ground-level ozone concentrations by reducing NOx emissions.

Response: See the preamble for discussion on CO limits.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 54

Comment: Finally, it is very poor public policy to discourage the beneficial use of process and other off-gasses and, thereby, increase the demand for and use of fossil fuels. In fact, it reverses EPA‘s previous efforts to encourage such use. For example, EPA has been encouraging beneficial reuse of landfill gas for the last decade and of process vents since at least the early 1990s [Footnote: Since the early 1990‘s the Part 60 and 63 regulations have encouraged combusting regulated vent streams as fuel, by waiving performance tests and monitoring where the vent is combusted as or with primary fuel.] For some facilities, it will be much more economical and incur much less compliance liability to incinerate Gas 2 streams, rather than send them to fuel uses. The energy needed to replace the lost heat capacity and the additional energy needed to incinerate the Gas 2 streams will come from additional fossil fuel production and use. This will result in a net increase in national emissions, waste natural resources and increase imports of fossil fuels.

Recommendation: Combine the two proposed Gas 1 and Gas 2 subcategories and apply only a revised tune-up requirement as discussed further in Comment Section V.

Response: See the preamble for discussion of achievability of emission limits and how we modified the gas 1 subcategory to be more inclusive of other fuel types.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 119

Comment: It is also important that the Agency fully evaluate the negative environmental impacts of forcing sources to install the full suite of controls needed here. The two primary environmental issues are the increased energy use required and the generation of additional emissions resulting from the control. Because oxidation catalyst requires a higher stack temperature than is optimal for a boiler or process heater some thermal efficiency will be sacrificed on each unit that has to install this technology. To achieve this will increase firing rates. Additionally, the controls themselves use electricity and generate solid and/or liquid wastes, the disposal of which requires energy (as well as cost and burdens). Because stack temperatures are not quickly quenched if oxidation catalyst is in place, dioxin/furan emissions are directionally increased. Furthermore, oxidation catalyst oxidizes SO2 to SO3, resulting in increased emissions of particulate (as sulfuric acid aerosol). The activated carbon systems needed for Hg and dioxin/furan control generate carbon particulate.

Recommendation: The Agency should include in its evaluation of the controls required for complying with this proposal the increased energy use and additional emissions that result from the controls.

Response: See the preamble for discussion on control device interactions.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 122

Comment: Theoretically, complete combustion will occur when the exact amount of oxygen necessary to chemically convert all of the fuel to combustion products is present. For pure hydrocarbon fuels (containing only C and H), the combustion products are carbon dioxide (CO_2) and water (H_2O). If less than the theoretical amount of oxygen is added, there is insufficient oxygen to convert all of the CO to CO_2. As less oxygen is added, CO increases and CO_2 decreases. If more than the theoretical amount of oxygen is added, CO remains zero and the excess oxygen simply mixes with and dilutes the combustion products. Because the excess oxygen (and nitrogen, if the oxidant is air) absorbs heat that is lost in the stack gases and hence lowers thermal efficiency, the optimum theoretical operating point for maximum thermal efficiency is with exactly 100% of the theoretical air required for complete combustion (i.e., zero excess O2).

Practical Relationship Between Excess O2, CO, Efficiency and Safe Operation

Thermal efficiency in boilers and process heaters is typically defined in terms the percentage of chemical energy in the fuel converted to heat and transferred to the working fluid (steam, process feed, etc.). The majority of lost heat normally consists of latent heat in the stack gases and uncondensed water vapor. CO and unburned carbon (hydrocarbons, soot, char, etc.) are combustible, and as such represent lost thermal energy. Under normal combustion conditions with low combustibles, the thermal energy loss is usually insignificant compared to other losses (except perhaps with solid fuel-fired units where unburned carbon can be significant). Only when combustibles rises to very high levels for CO, thousands of ppm do they begin to contribute significantly to efficiency loss. Elevated CO also indicates atmospheres that are corrosive to metals at high temperatures and hazardous to personnel if exposed, so there are reasons besides efficiency loss to maintain low CO.

In practical systems, complete combustion is generally not achieved when the theoretical amount of oxygen is added because of imperfections in fuel-air mixing and other factors. Because of this, boilers and process heaters operate with a certain amount of excess O2. CO typically begins to rise steeply as excess oxygen is reduced and approaches zero (Figure 2, left). In oil-fired systems, smoke (soot) concentration also rises, typically before CO appears. The point of maximum thermal efficiency is typically within 1 or 2 percent above zero percent excess O2, defined by the tradeoff between increasing heat losses due to heat absorbed by dry gases as excess O2 increases and increasing CO as it decreases. The exact point at which the optimum is reached depends on the furnace, burner design and other factors unique to individual units.

While it would maximize thermal efficiency to operate at the point of maximum efficiency, variations in air and/or fuel flow, especially during load swings, can potentially reduce excess O2 below the optimum, raising CO emissions. Operating with too little oxygen can extinguish the flame creating potentially explosive conditions in the combustion chamber, or trip the flame safety system (if so equipped) shutting down the unit. Due to mixing imperfections in practical systems, elevated CO also can lead to regions of the furnace gas that are deficient in oxygen, which leads to accelerated high temperature metal corrosion that can decrease the life of tubes, tube hangers, and other components and cause tube leaks and/or structural damage. These conditions are impractical and potentially dangerous. Therefore, it is a best practice to define the minimum excess O2 that can be reached while maintaining CO and smoke below moderate levels during tuning, then raise the excess O2 operating level above this point to provide a margin of safety. Guidelines for tuning industrial boilers typically give a modest CO level (e.g., 100 to 400 ppm) or, for oil-fired units, a Bacharach smoke spot number “SSN” or “BSN” - (e.g., SSN of 2 for distillate oil and SSN of 4 for residual oil) as the maximum levels commensurate with minimum excess O2. These limits are typically reached at excess O2 levels between 0.5% and 3.0% for gas-fired units and from 2.0% to 4.0% for oil-fired units. There are a number of references on boiler and process heater tuning that describes this general process of combustion tuning for optimum efficiency and low emissions. [Footnote: EPA, 1983. Combustion Efficiency Optimization Manual for Operators of Oil- and Gas-Fired Boilers. EPA-340/1-83-023, Stationary

Source Compliance Division, Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Washington, D.C.; Baukal, C.E. and Schwartz, R.E. The John Zink Combustion Handbook, CRC Press, Danvers, MA, 2001.]

Elevated CO emissions also can occur when excess O2 is too high (Figure 2, right). Flames are stabilized by recirculation of heat and radical species present at high temperatures from the flame back to the burner. At very high excess O2 levels, fuel concentrations and flame temperatures are low, reducing flame stability. Air velocity at the burner may exceed the flame speed, resulting in ignition instability and flame blow-off. It is very unsafe to operate in this region because potentially explosive fuel mixtures may be created in the combustion chamber that can cause severe mechanical damage and personnel hazard if the mixture in the furnace suddenly reignites from contact with hot surfaces. Most boilers and process heaters cannot reach this point at full load because of air supply limitations. However, this may occur in some systems at reduced load such as during normal turndown operations or during startup and shutdown.

Adverse Impacts of Minimizing CO

The discussion above emphasizes the optimization of excess O2, CO, smoke, efficiency and combustion stability to achieve maximum thermal efficiency commensurate with low emissions, safe operability and maintainability.

Response: See the preamble for discussion on CO limits.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 123

Comment: EPA has proposed or solicited comment on CO limits of 1 ppm for Gas 2 units and 2 ppm for Gas 1 metal furnaces. It may be possible in some systems to achieve these levels under certain operating conditions, typically near full load where combustion chamber temperatures are highest and at higher excess O2 levels. However, this is not universally true because combustion chamber temperatures, residence times and mixing characteristics influencing CO burnout vary among different designs, depending on the unit design duty and other factors. Operating with excess O2 greater than the optimum operating range to achieve minimum CO results in a significant thermal efficiency penalty and/or unacceptable proximity to safety boundaries of the operating envelope (Relationship Figure below, right). In addition to thermal efficiency, lower flame temperatures associated with higher excess O2 typically result in additional heat input to the furnace to maintain sufficient radiative heat transfer for the process (radiative heat transfer is proportional to temperature to the fourth power, and so is very sensitive to changes in flame temperature). Also, it may not be possible to achieve a specific low CO level at full load due to combustion air supply constraints. The consequence may be an effective de-rating of unit capacity to achieve that condition. Thus, minimizing CO rather than optimizing all key parameters generally could be expected to increase energy consumption and may constrain production.

Response: See the preamble for discussion on CO limits.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 126

Comment: Most boilers are designed to mix fuel and air at an appropriate ratio, and to provide sufficient residence time for the fuel to combust completely. Obviously, these factors are fuel-dependent, as a gaseous fuel will require less time for complete combustion than a liquid fuel, which in turn requires less time to burn than a solid fuel. The need for longer residence time is why the radiant sections in solid-fuel fired boilers are larger than for gas-fired units. The size of the boiler is typically optimized to allow for complete combustion, while minimizing the cost of construction materials.

Unfortunately, increasing the size of the radiant section is not an option for existing units. For these units, the strategy for lowering CO emissions is typically to raise the level of excess oxygen. The increase in oxygen concentration at a given unit load has two positive effects. First, raising the air flow rate increases air velocity at the burner, which may act to increase the rate of fuel-air mixing and decrease oxygen-deficient zones that provide pathways for escape of CO. Second, it tends to decrease the peak flame temperatures, reducing radiant heat transfer and raising furnace exit gas temperature, which speeds up CO oxidation reactions in the later stages of combustion, allowing more complete CO to occur. Offsetting these positive effects, increasing the air flow rate decreases bulk gas residence time in the furnace, reducing the time available for the relatively slow CO oxidation reactions to occur. To offset the decrease in radiative heat transfer, the fuel flow may need to be increased to meet process demand.

However, there are a number of negative impacts associated with operating a boiler or process heater at higher levels of excess oxygen. Many forced air and induced draft units do not have sufficient fan capacity to run with elevated excess oxygen at the high end of the load range. Therefore, these units would effectively be derated by such strategy.

The minimization of excess oxygen in boiler and process heater applications is a key feature for maximizing efficiency. The efficiency is defined by the amount of combustion air that is present, and the difference between the ambient temperature and the stack exhaust temperature. The more air that is heated up through the combustion process, the more heat is lost to the atmosphere, causing the unit to be less efficient. A less efficient unit will require more fuel to be fired to produce a given amount of steam. The additional fuel firing results in higher operating costs, and higher greenhouse gas and other emissions.

Minimizing the level of excess oxygen is also a primary strategy for reducing NOx emissions from a boiler or process heater. The NOx formation mechanisms are dependent upon the temperatures in the flame zone, and the stoichiometry. Reducing the level of excess oxygen increases peak flame temperatures but decreases oxygen availability, the net effect of which reduces the rate of thermal NOx formation. If there is less oxygen present, the monatomic nitrogen is less likely to be oxidized (and more likely to react with a second monatomic nitrogen to form diatomic nitrogen). Reducing excess oxygen typically reduces formation of both thermal NOx, and the ?fuel NOx‘ (NOx that is formed by the release of fuel-bound nitrogen). Therefore, increasing the level of excess oxygen typically results in higher NOx emissions.

Response: See the preamble for discussion on CO limits.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-2702.1
Comment Excerpt Number: 217

Comment: C. Recently PSD "Tailoring Rule" Must be Addressed.
Facilities will have to install extensive emission control equipment to meet the proposed Boiler MACT emission limits. Specifically, EPA stated in the preamble that emission control would likely require a fabric filter (FF) plus carbon injection plus wet scrubber control plus combustion improvements or carbon monoxide (CO) catalyst. The installation of this equipment could result in increases in emissions of CO2e or criteria pollutants. The following are examples:

In general the installation of additional emission control equipment will increase the pressure drop that a boiler’s induced draft (ID) fan will have to overcome. If the ID fan is not upgraded the boiler steaming capacity will decrease because the previous air–to-fuel ratio cannot be achieved resulting in the requirement to increase the firing rate of the other facility boilers. Combustion of additional fuel in the other on-site boilers may result in a significant emissions increase triggering PSD.

Operation of additional emissions control equipment will require more electricity. A facility’s unused electrical generating capacity would be required to meet this demand thereby requiring additional fuel combustion to generate the steam required for the steam turbine. Additional fuel burning may result in a significant emissions increase triggering PSD.

Facilities may be required to make operational changes in order to meet the Boiler MACT limits that could result in increases in emissions of CO2e or criteria pollutants. The following are examples:

Fuel switching for multi-fuel boilers may be required to meet the proposed boiler MACT emission limits. A specific example is multi-fuel (e.g. wood and some coal) boiler that has over-fired air and it must combust additional coal in order to decrease the emissions of CO. This change in firing ratio of fuels may result in a significant increase triggering PSD.

A biomass boiler may have to increase its operating target for excess oxygen level in order to decrease emissions of CO in order to meet the proposed boiler MACT emission limit. The result is that the flue gas flowrate increases to a level that is beyond the capability that existing fabric filter can handle reliably and the amount of fuel that can be burned in this boiler is now administratively limited to match the capability of the fabric filter. This requires that the facility operate the backup natural gas package boilers which have no heat recovery system (e.g. economizer or air heater) to make-up the difference rather than invest in a larger fabric filter needed to meet the proposed Boiler MACT limits.

These are but a few general examples, where there are many more to show how the PSD tailoring rule could be triggered due to changes facilities must make to achieve compliance with the proposed Boiler MACT rule.

Response: See the preamble for revised emission limits.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 254

Comment: Refinery heaters and vertical cylindrical heaters in general have much lower space heat release rates than package boilers. This is good and bad for CO destruction. For safety these heaters have a lower space heat release rate to prevent over heating of oil or other product in the tubes to prevent coking or fires. The lower space heat release rate (~20,000 Btu/cubic foot) is good for CO destruction. The large heater size causes other CO issues due to down draft of low temperature products of combustion along the heater walls. These low temperature products mix with the outside of the flame and quench CO (below 1,500 deg F) and cause a slight increase in CO.

* Reducing CO to extremely low levels may require that these boilers be de-rated in capacity to allow complete CO burnout.
* • To meet Low NOx and Low CO without back end catalysts will require existing package boilers to be significantly de-rated, by as much as 50%, and new boilers to be designed with furnaces approximately twice as big.
* To require very low CO in process heaters may require re-design of the burners with possible refractory walls to prevent quenching or back-end catalysts.

Response: See the preamble for discussion on CO limits.

Commenter Name: Matthew Todd and David Friedman

Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 255

Comment: Allowing reasonable CO levels also provides acceptable operation at lower loads when fuel-air ratio control is not as accurate. For both boilers and process heaters, at low loads, the temperatures in the furnace are significantly reduced and higher excess air is required. This is especially important in multi-burner boiler installations where NFPA does not allow air flow reduction below 25%. The mixing energy of the flame is also much lower and therefore CO always will increase at lower firing rates.

* Reducing CO to extremely low levels may significantly limit the operational turndown of many boilers and process heaters.
* Reducing CO to extremely low levels, and having no exception for operation during SSM periods, may limit the life of the units due to a need to increase the rate at which the unit is warmed up to minimize operation at lower loads.

Response: See the preamble for discussion on CO limits.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 256

Comment: Allowing reasonable CO levels also provides an achievable operating window for load following boilers. Typical metered control systems allow air to lead fuel on increasing load and fuel to lead air on decreasing load. This results in fuel lean operation during transient load conditions.

* Having to maintain tight CO limits may require that the speed of burner load changes be limited to prevent high excess air conditions that generate high CO. This may inhibit a boilers ability to respond as quickly as needed to changes in steam demand.

Response: See the preamble for discussion on CO limits.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 274

Comment: The addition of large fans, pumps, compressors, feeders and stack gas reheat coils translates directly into a significant increase in energy consumption compared to that for the unit prior to retrofit. Stack gas reheat alone would account for ~1.2% of fuel heat input assuming a required temperature rise from 145 0F to 200 0F. Some but not all of this increase may be recovered by tuning and by the additional heat recovery. It is unlikely that the increase could be offset by marginal thermal efficiency improvements that could be achieved by boiler tuning (~1%) or heat recovery associated with gas cooling between the oxidation catalyst and fabric filter (~0.5%).

The incremental energy consumption associated with add-on controls translates directly to incremental increases in emissions of not only HAPs but also carbon dioxide (CO_2, a greenhouse gas), NOX, SO2 and PM. Incremental energy consumption due to stack gas reheat, electric fans and pump drives (adjusted for fuel-to-electricity conversion heat rate) equates to several percent of fuel heat input. Increases in pollutant emissions will be approximately proportional to the energy increase. Increased HAP production due to energy consumption will at least partially offset HAP reductions achieved by add-on controls. An increase in other pollutants would be unwelcome at a time of sharply increasing pressure to decrease those emissions in light of emerging greenhouse gas rules, PM2.5 implementation and tightening of ozone, NO2 and SO2 ambient standards.

[See submittal for Attachment F's Figures 1 to 15.]

[See submittal for Attachment F's Attachment 1-Personal Communication E-mails.]

Response: See the preamble for discussion on revised limits.

Commenter Name: Michael J. Burns
Commenter Affiliation: Ever-Green Energy, LLC
Document Control Number: EPA-HQ-OAR-2002-0058-3126
Comment Excerpt Number: 1

Comment: Ever-Green Energy considers the Standards, as proposed, to excessively favor the combustion of natural gas to the detriment of the responsible combustion of other fuels. In doing so, the proposed MACT Standard undermines other key policies at the Federal, State and local levels that encourage the development and use of renewable fuels such as the combustion of biomass. The proposed MACT Standards severely compromise the ability to develop unique energy systems such as the one Ever-Green Energy operates in Saint Paul, Minnesota; a facility that is acclaimed nationally and internationally for it's unique combination of energy efficiency coupled with renewable fuels.

The approach of the proposed MACT Standards which poses onerous requirements on a number of widely-utilized fuels also runs contrary to Federal policies that seek to improve the United States' energy security. Energy independence at the national level can best be accomplished by responsibly utilizing a variety of native fuels, especially clean renewables. The Standards as proposed will result in a trend toward increased combustion of natural gas and a decline in the use of many other fuels, including renewable fuels, that are critical in achieving a secure and reliable energy supply. The emission levels proposed in the MACT standard are not reasonable for many of the fuels that are relied upon to achieve the desired diversification of sources, including clean wood residuals that Ever-Green Energy and its affiliates rely upon.

Response: The carbon emissions from biomass are not within the scope of this rulemaking. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source, and see the preamble for the revised limits.

Commenter Name: Marvis A. Lewallen
Commenter Affiliation: Clearwater Paper
Document Control Number: EPA-HQ-OAR-2002-0058-2862
Comment Excerpt Number: 1

Comment: The existence of biomass boilers to receive woody material means that hundreds of thousands of tons of forest slash is burned in controlled combustion rather than in open burn piles. As EPA research has previously established, routing biomass to boilers has a profound beneficial impact on hazardous air pollutant emissions. For example, in its paper published by Paul Lemieux of EPA's National Risk Management Research Laboratory, benzene emissions from the open burning of Douglas fir slash was estimated at 196 mg/kg. [Reference: Lemieux et al, Emissions of Organic Air Toxics from Open Burning: A Comprehensive Review; Table 6; Progress in Energy and Combustion Science 30 (2004)] The estimated benzene emissions from the controlled burning of Douglas fir slash in a biomass boiler is less than 5 mg/kg. This means that every ton of slash burned in the forest results in approximately 40 times more benzene than had that same ton been burned in a biomass boiler. By adding unduly burdensome regulations that force companies that operate biomass boilers to stop burning biomass, EPA will cause the diversion of slash to open burning with the net result being a significant increase in hazardous air pollutant emissions.

Response: The EPA thanks the commenter for their input, but the EPA did not have ample time or data to analyze the potential impacts the rule may have on open burning.

Commenter Name: Pamela F. Faggert
Commenter Affiliation: Dominion
Document Control Number: EPA-HQ-OAR-2002-0058-2908.1
Comment Excerpt Number: 1

Comment: Dominion owns and operates an 83 MW biomass facility (consisting of 3 wood-burning boilers) in Hurt, Virginia and is considering additional biomass power investments to enhance its portfolio of renewable and carbon-neutral generation. Such investments will require reasonable environmental regulations that can be met with currently available and economically feasible emissions control technology. As a matter of public policy, EPA should encourage the combustion of biomass as substitute fuel for coal or oil. The combustion of biomass will become increasingly important to utilities as renewable portfolio standards (RPS) or targets are adopted by more states and are possibly applied to all states as a result of federal mandates. The combustion of biomass may also have an important role as an option for achieving existing or anticipated greenhouse gas emission (GHG) reduction goals or targets. Biomass power is a key strategy for many utility companies, including Dominion, in the southeastern U.S., since there are more limited renewable energy resources than in other parts of the country. In addition, biomass power utilizing waste wood is currently the lowest-cost commercially available renewable generation option that is also a base-load (dispatchable) generation resource. Unfortunately, the stringent MACT limits proposed for industrial boilers burning biomass will greatly inhibit the combustion of biomass in the future and could discourage companies from combusting biomass over more traditional fossil fuels, making it increasingly difficult for companies to meet RPS and GHG requirements and/or reduction goals. The cost of adding controls for biomass could be extensive, potentially inhibiting the development of new biomass facilities.

Response: The emission limits are revised for the final rule, see the preamble for discussion. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source.

Commenter Name: Robert Bauer
Commenter Affiliation: Kentucky Forest Industries Association
Document Control Number: EPA-HQ-OAR-2002-0058-3186.1
Comment Excerpt Number: 1

Comment: Reduction in the use of wood and woodwaste as fuel
The proposed rules impose severe emission restrictions on the combustion of biomass. Since many facilities may not be able to afford the controls required to meet the proposed MACT limitations, it appears that the proposed rules will drive these facilities towards the combustion of natural gas to meet energy requirements. Since biomass is a renewable source of energy, this appears to run contrary to the current Administration’s stated desire to move away from fossil fuels and toward renewable sources. Kentucky, along with other States, is facing mandatory renewable energy targets in the future. For obvious reason, wind, solar, geothermal and many other renewable sources are not viable in Kentucky. Biomass appears to be the primary alternative. Our state may not be able to meet its goals if biomass usage is discouraged. Additionally, given the current Administration’s desire to regulate Greenhouse Gas emissions, it is perplexing to the Department that the EPA would drive facilities away fro utilizing what may be considered a “carbon neutral” fuel. Furthermore, when combined with the recently proposed solid waste definition, it appears that the fate of wood residuals may be landfills, where it will decay into methane, which has a CO_2 equivalence of 25:1

Response: The topic of carbon neutrality and biomass emissions is outside the scope of this rulemaking. Further, EPA recognizes that the situation of each affected entity is different, and although some facilities may opt to switch to natural gas in lieu of biomass combustion, the data show that many biomass facilities are at or below the final emission limits, suggesting that many facilities will adopt biomass fuel specifications or install controls in order to meet the emission limits. The emission limits are revised for the final rule, see the preamble for discussion. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source.

Commenter Name: Kristine M. Krause
Commenter Affiliation: Wisconsin Electric Power Company, We Energies
Document Control Number: EPA-HQ-OAR-2002-0058-2679.1
Comment Excerpt Number: 1

Comment: We Energies is currently seeking approval to construct a 50 megawatt (MW), biomass-fired cogeneration facility at the Domtar Mill in Rothschild, Marathon County, Wisconsin. While we are concerned with many aspects of this proposed rule, We Energies is especially concerned with the potential negative impacts that the proposed rule could have on this project and other biomass projects in the future. This is an especially critical concern in states, such as Wisconsin, that have Renewable Portfolio Standards in place. In addition, the proposed rule significantly impacts We Energies' Milwaukee County Power Plant located in Wauwatosa, Wisconsin. Milwaukee County Power Plant is a cogeneration facility with three coal-fueled stoker boilers that

provide chilled water and heating steam to the Milwaukee Regional Medical Complex. There is currently no other source in place for these critical services.

Response: The emission limits are revised for the final rule, see the preamble for discussion. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source.

Commenter Name: Richard Lovely
Commenter Affiliation: Grays Harbor PUD
Document Control Number: EPA-HQ-OAR-2002-0058-2770.1
Comment Excerpt Number: 1

Comment: We believe that while the rule may be well intentioned, it would undermine the ability of utilities in Washington State, including Grays Harbor PUD, to comply with renewable energy mandates. It would create a disincentive for development of renewable biomass energy generation nationwide

Response: The carbon emissions from biomass are not within the scope of this rulemaking. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source, and see the preamble for the revised limits.

Commenter Name: Patrick Strauch
Commenter Affiliation: Maine Forest Products Council
Document Control Number: EPA-HQ-OAR-2002-0058-3120.1
Comment Excerpt Number: 1

Comment: Burning wood and paper mill sludge (which is a wood byproduct) replaces the use of expensive fossil fuels at many Maine mills. Wood energy is clean and has a much smaller carbon footprint than fossil fuels. The proposed rules will disadvantage existing and future wood burning boilers. We believe this will be counterproductive in the effort to reduce pollution.

First, it is important that we note that the Maine Forest Products Council represents a diverse mix of 350 forest products related companies in Maine. Concerning manufacturers, we represent companies from small individually operated saw mills, to major paper producers employing hundreds of individuals. Of the 49 total boilers that will be affected in Maine, 33 of them are boilers located in forest products facilities.

Response: The emission limits are revised for the final rule, see the preamble for discussion. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source.

Commenter Name: Chris M. Hobson
Commenter Affiliation: Southern Company
Document Control Number: EPA-HQ-OAR-2002-0058-2741.1
Comment Excerpt Number: 1

Comment: The stringent limits and requirements in the proposed IB MACT decrease the prospect of producing reliable renewable energy from biomass, since the resulting limits are virtually unachievable at many sources. Without the capability of producing renewable energy from new and/or converted biomass-fired boilers, the Southeast’s renewable energy resources will be further constrained.

Implementing this rule as proposed potentially affects both existing and new biomass-fired boilers. “Existing” sources face the prospect of potentially adding additional emission controls to meet the proposed emission limits for existing sources. These controls will be costly. The stringency of the proposed limits for “new” biomass sources may actually be a disincentive to proceeding with new boilers or with boiler conversions, thus eliminating the renewable energy and greenhouse gas (GHG) reduction benefits achieved by using a carbon neutral fuel - biomass.

Response: The carbon emissions from biomass are not within the scope of this rulemaking. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source, and see the preamble for the revised limits.

Commenter Name: Jeffrey R.Klieve
Commenter Affiliation: Monsanto Company
Document Control Number: EPA-HQ-OAR-2002-0058-2754.1
Comment Excerpt Number: 1

Comment: Monsanto operates several industrial boilers at various manufacturing facilities which would be impacted by the Boiler/PH MACT. This includes boilers fired with coal or natural gas with the ability to co-fire seed corn or hydrogen as alternative fuels in order to provide steam for the facilities' manufacturing operations. The alternative fuels provide important energy and heating value that reduce the amount of fossil fuels required to be burned to meet required steam demand. Firing seed corn, a renewable biomass fuel, also reduces overall emissions of greenhouse gases that would otherwise result from burning fossil fuels. Substituting hydrogen as a boiler fuel directly reduces GHG emissions as well as hazardous air pollutants (HAPs) that would occur from burning natural gas.

Response: See the preamble for discussion of combination fuel units.

Commenter Name: Deb Hawkinson
Commenter Affiliation: Hardwood Federation
Document Control Number: EPA-HQ-OAR-2002-0058-2781.1
Comment Excerpt Number: 1

Comment: Hardwood lumber is dried in kilns powered by boilers. Most boilers in the hardwood industry are run on sawdust and other waste from the production process, and many would qualify as "large" boilers (>10 million BTUs) under the proposed rule. Large amounts of fuel are needed to dry wood in the kilns, which have capacities ranging from 30,000 to 2,000,000 square feet. Some hardwood facilities use their own wood waste to fuel their boilers, while others buy all or some of their wood waste from other companies like furniture or pallet manufacturers. These manufacturers would often take their wood dust to local municipal solid waste facilities for disposal if it were not purchased by hardwood processors.

There is a significant risk that, at least for those companies who could continue operations given the higher costs of compliance, boilers would be converted from wood waste to natural gas should this rule go into effect. There are sometimes challenges in obtaining enough wood waste to power the boilers – as furniture and other wood manufacturers move overseas, lumber manufacturers must look elsewhere for wood waste. Some have come up with creative solutions, including providing free surfacing work in order to obtain wood dust. Several companies in our industry used natural gas boilers in the past, converting to biomass as costs rose. This was long before our government recognized this conversion as a positive energy step. Should costs for biomass rise, it is likely that many will stop using these renewable byproducts of wood manufacturing, preferring less environmentally friendly fossil fuels.

One small hardwood business owner who operates three manufacturing facilities with boilers running on wood waste offered the following observation:

Obviously, any added costs to drying lumber are going to reduce our already elusive profits in a declining industry. The consequences of the MACT program could cause lumber drying operations such as ours to convert back to non renewable resources such as fuel oil or natural gas. Then the wood waste would have to be disposed of in the landfill causing us to burn more diesel fuel to get it there and filling up the land fills. We currently have a very efficient system because the wood waste is often consumed at the point where it is. I can't begin to calculate how much it would cost if we had to truck our wood waste from the saw mill and concentration yard to the landfill, this would be ludicrous.

Response: The emission limits are revised for the final rule, see the preamble for discussion. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source.

Commenter Name: Edward Bortz
Commenter Affiliation: SP Newsprint Co LLC
Document Control Number: EPA-HQ-OAR-2002-0058-3128
Comment Excerpt Number: 1

Comment: The Rule Will result in Increased Negative Environmental Impacts
We respect EPA's job is to protect air quality. However, the existence of biomass boilers to receive woody material means that hundreds of thousands of tons of forest slash is burned in controlled combustion rather than in open burn piles. As EPA research has previously established, routing biomass to boilers has a profound beneficial impact on hazardous air pollutant emissions. For example, in its paper published by Paul Lemieux of EPA's National Risk Management Research Laboratory, benzene emissions from the open burning of Douglas fir slash was estimated at 196 mg/kg. [Reference: Lemieux et al, Emissions of Organic Air Toxics from Open Burning: A Comprehensive Review; Table 6; Progress in Energy and Combustion Science 30 (2004)] The estimated benzene emissions from the controlled burning of Douglas fir slash in a biomass boiler is less than 5 mg/kg. This means that every ton of slash burned in the forest results in approximately 40 times more benzene than had that same ton been burned in a biomass boiler. By adding unduly burdensome regulations that force wood products companies such as ours to stop burning biomass, EPA will cause the diversion of slash to open burning with the net result being a significant increase in hazardous air pollutant emissions.

Overly burdensome regulation will also result in similar increases in greenhouse gas emissions. The definitive study assessing the use of biomass to generate electricity is the May 2008 report entitled Bioenergy and Greenhouse Gases, prepared by Gregory Morris, PhD of The Renewable Energy Program of the Pacific Institute in Berkeley, California. This report notes that the use of biomass avoids the need to combust fossil fuels and also notes that because the combustion of biomass adds no net new carbon to the atmospheric-biospheric circulation system, it is considered "carbon neutral." Additionally, the study went beyond these comparatively simplistic conclusions to evaluate whether and how the change in terrestrial biomass (i.e., forest thinning) affects overall sequestration as well as the impacts of the change in timing and mix of carbon forms that occur depending on the fate of biomass. This detailed analysis concludes that greenhouse gas sequestration is enhanced by the forest thinning that generates much slash. Of greater importance, however, is the benefit achieved by avoiding open burning and/or decomposition (composting) of slash. Open burning and low-efficiency combustion (i.e., fireplaces) result in much higher emissions of methane, a potent greenhouse gas, as compared to controlled combustion in a boiler such as SSE's. Biomass that is left to decompose in the forest or is landfilled degrades into a 50-50 mixture of methane (CH_4) and carbon dioxide (CO_2). The report notes that due to the much higher global warming potential of methane, as compared to carbon dioxide, the global warming impacts associated with decomposition exceed those of controlled combustion even though less carbon is released into the atmosphere from natural decomposition over a 100-year period. In summary, Dr. Morris' team concluded that for every ton of biomass combusted to make electricity, you avoid 0.8 tons of greenhouse gas (CO_2 -equivalent) as a result of avoided fossil fuel use. For the biomass originating as slash, there is an additional net reduction of greenhouse gases of between 0.22 tons and 2.28 tons, depending on how the slash would have been handled if it had not been routed to controlled combustion. [Reference: Morris; Bioenergy and Greenhouse Gases, Table 4, Green Power Institute of The Renewable Energy Program of the Pacific Institute, May 2008]. This means that by combusting biomass our facilities reduce GHGs by 1.42 tons for every bone dry ton of slash that they combust.

It is not economical to haul biomass long distances. The closure of one of our boilers will have the immediate impact of increasing the amount of biomass that is disposed of through open burning and/or landfilling. This will have the exact opposite effect that EPA is hoping for through promulgation of the NESHAP.

Response: The EPA thanks the commenter for their input, but the EPA did not have ample time or data to analyze the potential impacts the rule may have on open burning. Furthermore, the carbon emissions from biomass is not within the scope of this rulemaking. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source, and see the preamble for the revised limits.

Commenter Name: Sean M. O'Keefe
Commenter Affiliation: Alexander and Baldwin, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-3196
Comment Excerpt Number: 2

Comment: In addition to producing all of the electrical power required by the factory and the rest of the plantation, the Puunene Mill power plant, along with two hydroelectric plants installed in the plantation irrigation system, together provide about seven percent of the electrical power supplied to Maui residents and businesses by the local utility. Thus, power generated by the plantation comprises a significant component of the utility's state-mandated renewable energy portfolio. In addition, HC&S is seeking to transition from a commodity sugar producer to an energy plantation with the aim of increasing its already substantial renewable energy production, thereby allowing it to continue to supply a significant portion of Maui's electricity needs while eventually reducing or even eliminating the use of fossil fuels. The potential costs of compliance with the Boiler MACT may make this transition, and indeed HC&S' continued operation, infeasible. This could jeopardize the state's ability to meet its renewable energy objectives, and would also be inconsistent with the Obama administration's goals of expanding renewable energy, decreasing dependence upon foreign sources of oil, and reducing greenhouse gas emissions.

Response: See preamble for discussion on revised limits and biomass definition.

Commenter Name: Allen Sanders
Commenter Affiliation: AbitibiBowater
Document Control Number: EPA-HQ-OAR-2002-0058-3177.1
Comment Excerpt Number: 2

Comment: Proposed boiler limits will be difficult or, in some cases, impossible to reach—will drive us away from the use of biomass, a renewable, clean energy source, and toward a greater reliance on foreign-sourced fossil fuel.

Response: The emission limits are revised for the final rule, see the preamble for discussion. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source.

Commenter Name: Michael J. Burns
Commenter Affiliation: Ever-Green Energy, LLC
Document Control Number: EPA-HQ-OAR-2002-0058-3126
Comment Excerpt Number: 2

Comment: The emission levels proposed in the MACT standard are not reasonable for existing plants in that many will require substantial retrofit in order to meet the standards. Even with these substantial retrofits, the ability to consistently meet the proposed emissions standards remains in doubt due to the drastic levels to which the emission levels are being limited. In the case of the facility that Ever-Green Energy operates, the location of the facility and limited space for expansion could cause us to be unable to meet the standards. Ironically, the MACT Standard, as proposed, could cause existing energy facilities that are recognized for their energy efficiency and use of renewable fuels, such as the one in Saint Paul, Minnesota, to be made obsolete at a time when tens of millions of dollars in grants, subsidies, and incentives are being paid by the Federal government to promote such facilities.

Response: The emission limits are revised for the final rule, see the preamble for discussion. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source.

Commenter Name: Carolyn Van Asten
Commenter Affiliation: Packaging Corp. of America
Document Control Number: EPA-HQ-OAR-2002-0058-3159
Comment Excerpt Number: 2

Comment: The strict standards set by the rule, sometimes nearing emittance levels that are undetectable, will not only affect fossil fuel boilers, but biomass and biogas boilers as well. In some cases, the limits imposed on these renewable energy sources are more stringent than the limits of fossil fuel boilers. I believe these limits will deter new implementation or continued use of these renewable energies.

Response: The emission limits are revised for the final rule, see the preamble for discussion. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source.

Commenter Name: Patrick Strauch
Commenter Affiliation: Maine Forest Products Council
Document Control Number: EPA-HQ-OAR-2002-0058-3120.1
Comment Excerpt Number: 2

Comment: From a large forest products manufacturer (such as a paper mill) perspective, we believe that facilities with biomass boilers will be penalized. The new emission limits may be unachievable, and will discourage mills from exploring new methods to power their facilities with renewable resources. Sludge at many mills, that is now being burned safely, may have to be land-filled.

Response: The emission limits are revised for the final rule, see the preamble for discussion. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source.

Commenter Name: Kellie Daniels
Commenter Affiliation: Grays Harbor Chamber of Commerce
Document Control Number: EPA-HQ-OAR-2002-0058-2815.1
Comment Excerpt Number: 2

Comment: We understand that if this rule is enacted, local business Sierra Pacific Industries will be forced to install equipment in newly-constructed biomass cogeneration facilities without any indication that the equipment will actually help them achieve the necessary air quality standards. If they cannot make the standards, they will have to find other energy sources, most likely fossil fuels.

Response: The emission limits are revised for the final rule, see the preamble for discussion. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source.

Commenter Name: Catherine H. Reheis-Boyd
Commenter Affiliation: Western States Petroleum Association
Document Control Number: EPA-HQ-OAR-2002-0058-3190.1
Comment Excerpt Number: 3

Comment: If this proposal is adopted without changes, it would require the installation of control devices that have not been demonstrated to achieve the proposed numeric emission limits and that would, in actuality, increase energy consumption and very possibly increase emissions.

Response: See the preamble for discussion on revised limits.

Commenter Name: Bobby B. Howell
Commenter Affiliation: Mississippi House of Representatives
Document Control Number: EPA-HQ-OAR-2002-0058-3193
Comment Excerpt Number: 3

Comment: This rule will drive us away from the use of biomass, a renewable, clean energy source, and push us toward a greater reliance on foreign-sourced fossil fuel.

Response: The emission limits are revised for the final rule, see the preamble for discussion. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source.

Commenter Name: Richard Lovely
Commenter Affiliation: Grays Harbor PUD
Document Control Number: EPA-HQ-OAR-2002-0058-2770.1
Comment Excerpt Number: 3

Comment: We encourage EPA to reexamine its proposed rule and work to develop a reasonable and responsible rule that is achievable and supports the state and federal policy objectives of encouraging investment in renewable resources.

Response: The carbon emissions from biomass are not within the scope of this rulemaking. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source, and see the preamble for the revised limits.

Commenter Name: Mark Calmes
Commenter Affiliation: Archer Daniels Midland Company
Document Control Number: EPA-HQ-OAR-2002-0058-2927.1
Comment Excerpt Number: 4

Comment: The use of digester gas can prevent emissions of potent methane GHGs from wastewater treatment plants, minimize sludge production, and conserve natural gas usage. Further, its use would not be expected to cause an increase in any HAPs, and any potential increase in SO2 emissions could be readily controlled by conventional means. Despite these benefits, if digester gas combustion causes a unit to be regulated under Gas 2, the gas would likely not be burned in boilers or process heaters. Instead, it would be flared resulting in an increase in both fuel usage and emissions.

Response: See the preamble for discussion of achievability of emission limits and how we modified the gas 1 subcategory to be more inclusive of other fuel types.

Commenter Name: Cynthia L. Karlic
Commenter Affiliation: NRG Energy, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2822.1
Comment Excerpt Number: 4

Comment: EPA has proposed HAPs standards based on whether an ICI Boiler is located at a Major or Area Source of HAPs. For New Biomass boilers at a Major Source, EPA has proposed standards for Particulate Matter ("PM"), Hydrogen Chloride ("HC1"), Mercury ("Hg"), Carbon Monoxide ("CO"), and Dioxins/Furans ("DIE") whereas similar biomass boilers at an Area Source would only be regulated for PM and CO.

Biomass fired generation is an important renewable energy resource. Having significantly more HAPs limits for biomass boilers located at a Major Source severely disadvantages companies that want to repower/modify existing generating boilers to use biomass in favor of new biomass generation at Greenfield sites even though the biomass-fired boiler at each site may be the same size and therefore, by itself be an Area Source of HAPs.

Existing generating boilers being converted to biomass firing have an advantage of a location at an already developed site, the ability to use existing equipment (such as the turbine/generator), and a knowledgeable work staff. To require these boilers to meet additional emission requirements not required by a boiler at an Area Source, increases the cost of the project and may, in same cases, prevent the conversion project from moving forward due to physical limitations that may exist to installing the additional controls required to meet the HC1, Hg, and D/F standards. The result will be a higher cost of energy from biomass-fired generation either because the boiler at the Major Source will have a higher than needed capital cost or Greenfield based biomass-fired generation will be the only type of this renewable energy. In addition, for states, such as Connecticut, that have established Renewable Portfolio Standards ("RPS") and have limited other options for in-state renewable energy, the ability of the state to meet its RPS can be harmed.

Response: The emission limits are revised for the final rule, see the preamble for discussion. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source.

Commenter Name: J. Michael Geers
Commenter Affiliation: Duke Energy
Document Control Number: EPA-HQ-OAR-2002-0058-2765.1
Comment Excerpt Number: 4

Comment: The Proposed Limits for Biomass-Fueled Boilers Are Flawed and Will Impede the Construction of Electric Generating Biomass Units
Many states have adopted Renewable Portfolio Standards (RPS) expressly for the purpose of encouraging the development and deployment of biomass fired units as a matter of public policy. The MACT standards EPA has proposed for biomass-fired boilers will create a huge barrier to the development of renewable energy biomass projects, which will cause many to be cancelled because of the choices EPA has made in developing these proposed standards. As a matter of public policy, EPA should encourage the combustion of wood biomass. The combustion of biomass is becoming increasingly important to Duke Energy and other utilities as renewable energy laws are adopted by more states, and are possibly applied to all states as a result of federal mandates. Section 112 affords EPA great flexibility in how it establishes MACT standards for these sources even after considering the recent guidance EPA has received from the courts. The combustion of biomass has the beneficial effect of conserving natural resources. Unfortunately, the stringent MACT limits EPA has proposed for IBs burning biomass will greatly inhibit the combustion of biomass in the future. This uncertainty is causing biomass projects to be postponed and will lead to project cancellations and state renewable energy goals not being met.

Response: The emission limits are revised for the final rule, see the preamble for discussion. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source.

Commenter Name: Eric Trauner
Commenter Affiliation: Citizen
Document Control Number: EPA-HQ-OAR-2002-0058-2768
Comment Excerpt Number: 4

Comment: In an era of debate about anthropogenic global warming, it's unwise to put excessive demands on use of biomass and energy-intensive solid waste. US-EPA acknowledges that biomass is a carbon-neutral fuel source. Furthermore, there will be increased landfilling of biomass as well as energy-intensive solid waste under this proposal. Not only will this strain landfill space, but anaerobic decay of biomass and solid waste produces methane gas, a decidedly more potent greenhouse gas than carbon dioxide. Indeed, a strong case can be made that US-EPA should be encouraging use of biomass and solid waste as fuel rather than landfilling, in order to reduce net greenhouse gas impact.

Response: The emission limits are revised for the final rule, see the preamble for discussion. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source.

Commenter Name: Dustin Madlung
Commenter Affiliation: Citizen
Document Control Number: EPA-HQ-OAR-2002-0058-3160
Comment Excerpt Number: 4

Comment: I also always hear about investing in renewable resources/using renewable resources in the news, and based on the information I have heard from professionals in the field is that the Boiler MACT punishes biomass fuels as well as biogas fuels from landfills and sewage lagoons pretty hard and strongly favors natural gas boilers. This is also not counting the additional energy that is going to be consumed from running the additional emission control technologies that are going to be required to be installed.

Response: The emission limits are revised for the final rule, see the preamble for discussion. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source.

Commenter Name: Kellie Daniels
Commenter Affiliation: Grays Harbor Chamber of Commerce
Document Control Number: EPA-HQ-OAR-2002-0058-2815.1
Comment Excerpt Number: 4

Comment: The proposed rule also threatens the ability of our not-for-profit, community-owned Public Utility District to meet state mandates for renewable resources. Grays Harbor PUD recently entered into a contract with Sierra Pacific to purchase the renewable biomass energy in order to comply with the Energy Independence Act. Under the Act, the PUD is mandated to provide 15 percent of the energy need to serve its customers from eligible renewable resources by 2020. The mandate stair-steps into place with 3 percent required in 2012, 9 percent by 2016 and 15 percent by 2020. The biomass energy the PUD is purchasing from Sierra Pacific Industries is considered an eligible resource under the Act and is critical for compliance with the state law. We are concerned this rule would result in the PUD having to seek another resource at likely a higher cost. This puts pressure on ratepayers and all businesses in the county that rely on the PUD for electricity.

Response: The emission limits are revised for the final rule, see the preamble for discussion. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source.

Commenter Name: Jacquelyn Taylor
Commenter Affiliation: South Carolina Pulp and Paper Association
Document Control Number: EPA-HQ-OAR-2002-0058-3154.1
Comment Excerpt Number: 5

Comment: Metso, a leading provider of combustion technology, has concluded that "the proposed ruling will discourage, if not eliminate, new development of renewable biomass power."

Response: The emission limits are revised for the final rule, see the preamble for discussion. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source.

Commenter Name: Dave Copeland
Commenter Affiliation: Praxair Inc
Document Control Number: EPA-HQ-OAR-2002-0058-3141
Comment Excerpt Number: 5

Comment: In many cases this "other gas" is a byproduct and it is very desirable from both an energy efficiency and an environmental viewpoint that this gas be utilized. To ensure that there is no disincentive for the utilization of "other gas", the emission limits should be no more stringent than any of the other fuel types.

Response: See the preamble for discussion of achievability of emission limits and how we modified the gas 1 subcategory to be more inclusive of other fuel types.

Commenter Name: Chris Jamer
Commenter Affiliation: Oregon Forest Industries Council
Document Control Number: EPA-HQ-OAR-2002-0058-2928.1
Comment Excerpt Number: 5

Comment: OFIC members are concerned with the ramifications of implementing new control technologies. In addition to significant capital cost, EPA must consider other things including energy use, availability of the expertise to install equipment, ability of companies to implement the monitoring required to determine compliance, as well as a host of other issues.

One example is implementing carbon injection to control dioxin. Carbon powder injected into the air emissions will precipitate the dioxin, literally allowing the carbon/dioxin mixture to settle out at the bottom of the stack. That sounds simple and ideal, but the process creates a significant amount of by-product, consisting of a dioxin and mercury laced carbon powder. How does a company dispose of that waste? Would it be considered a hazardous waste? Given its constituents, the by-product might need to be hauled some distance to an approved waste disposal site, creating the environmental (and economic) impacts of significant fossil fuel use.

To put this in context for effectiveness, company experts opined that the level of dioxin removed via this process was likely far less than the dioxin levels produced by backyard burning in their small rural community. EPA would be choosing a hugely expensive approach with essentially negligible human health protections but with significant safety and health concerns.

Response: See the preamble for discussion on dioxin/furan emission limits and the reduced testing program. It is expected that very few sources will install activated carbon injection for dioxin/furan control as a result of the changes made to the dioxin/furan emission limits.

Commenter Name: Thomas D. Evans
Commenter Affiliation: Coastal Resources Company
Document Control Number: EPA-HQ-OAR-2002-0058-2865.1
Comment Excerpt Number: 6

Comment: The proposed rule would probably cause many biomass boilers to convert to natural gas, because that would be the only option that they could afford. If Coastal switched, its annual natural gas cost would be $10 million, at current prices, and 150,000 tons of wood-fuel would be piled up somewhere. If all U.S. softwood panel & lumber producers switched, the incremental annual natural gas cost would be $1-2 billion, we would consume 1-2% of total U.S. natural gas withdrawals (which would significantly disrupt the natural gas market), and 20 million tons of wood-fuel would be piled up somewhere to rot, which would definitely not be "Green".

Response: EPA is not requiring fuel switching to natural gas in the final rule. Further, based on the data from best performing units in the biomass subcategory several units firing biomass are meeting the final emission limits. Therefore, EPA does not expect all of the units firing biomass to switch to natural gas as a compliance option; as a result, the EPA determined that the estimated landfilled biomass and increased natural gas usage noted by the commenter are overestimated. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 for further discussion on biomass.

Commenter Name: Dale A. Riddle
Commenter Affiliation: Seneca Sustainable Energy
Document Control Number: EPA-HQ-OAR-2002-0058-2866.1
Comment Excerpt Number: 6

Comment: Wood is not only the preferred environmental choice of building products, it is also a superior source for energy creation. Trees are created by solar energy and they are renewable in perpetuity. Unlike steel and brick, they take very little energy to manufacture, as all you need to do is turn round wood into rectangles. And, they cause a net decrease, not increase, in global warming gases in our atmosphere.

Citizens and community leaders from all segments of the political spectrum support the use of biomass to create energy.

The United States Department of Energy has called for the doubling of electrical power generated from biomass plants. The European Union identified biomass cogeneration as a primary means of increasing energy efficiency and decreasing greenhouse gas emissions. This was stated by the EU in Directive 2004/8/EC of the European Parliament and the Council of 11 February 2004 (on the promotion of cogeneration):

"The increased use of cogeneration geared towards making primary energy savings could constitute an important part of the package of measures needed to comply with the Kyoto Protocol to the United Nations Framework Convention on Climate Change, and of any policy package to meet further commitments. The Commission in its Communication on the implementation of the first phase of the European Climate Change Programme identified promotion of cogeneration as one of the measures needed to reduce the greenhouse gas emissions from the energy sector and announced its intention to present a proposal for a Directive on the promotion of cogeneration in 2002."

This quotation demonstrates the international recognition of the benefits of cogeneration plants, such as the proposed SSE facility. It also mirrors the more local sentiment expressed by Governor Kulongoski:

"I want you to know that I am committed to making Oregon a national leader in forest biomass energy development. . . . Our forests make biomass a natural fit for Oregon. We will be able to reduce the risk of forest fires by removing dry debris — and then use that debris to generate energy, all the while creating jobs, attracting new businesses, and shifting our economy into a higher gear." Gov. Ted Kulongoski. ielth Annual Leadership Summit, Jan. 2006.

In a different forum, Government Kulongoski stated:

"I am honored to support the Seneca Sustainable Energy project. This project represents an excellent example of how we get people back to work in Oregon and continue to serve as a model for the entire country of how to grow a new economy where economic prosperity is tied directly to our commitment to a sustainable future." Governor Ted Kulongoski, November 19, 2009.

EPA needs to recognize the impact of its rules, including unintended impacts. These include increased HAP and greenhouse gas emissions in our atmosphere through additional uncontrolled combustion of biomass.

Response: The emission limits are revised for the final rule, see the preamble for discussion. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source.

Commenter Name: David Bonistall
Commenter Affiliation: NewPage Corp
Document Control Number: EPA-HQ-OAR-2002-0058-2920.1
Comment Excerpt Number: 7

Comment: The increased use of renewable fuels such as woody biomass is part of our national energy and climate policy. Providing this alternate TSM compliance strategy will provide a compliance mechanism that will not disadvantage the use of wood fuel and potentially create the unintended consequence of replacing woody biomass fuel with fossil fuel.

Response: The EPA has not adopted a TSM alternative.

Commenter Name: Edward Bortz
Commenter Affiliation: SP Newsprint Co LLC
Document Control Number: EPA-HQ-OAR-2002-0058-3128
Comment Excerpt Number: 10

Comment: Our industry sector has been ravaged by the economy and the volatility of fossil fuel prices. It is simply not an option to convert to exclusively natural gas as a fuel so as to maintain a bearable level of regulation. Biomass is a low-HAP fuel and should not be unduly penalized through the NESHAP process. Doing so will result in plant closures, unemployment and further flight of manufacturing operations overseas where the level of regulation is substantially lower. EPA must bring a dose of reality to the table and recognize that the impact of its rules will be increased HAP emissions through additional uncontrolled combustion of biomass and decreased domestic employment. Congress never intended such draconian effects from the NESHAP program.

Response: EPA recognizes that the situation of each affected entity is different, and although some facilities may opt to switch to natural gas in lieu of biomass combustion, the data show that many biomass facilities are at or below the final emission limits. This suggests that many facilities will adopt biomass fuel specifications or install controls in order to meet the emission limits. Furthermore, EPA has determined that changes from the proposal have reduced economic impact on many biomass facilities; see the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 for further discussion on biomass.

Commenter Name: Thomas Bakk
Commenter Affiliation: State of Minnesota Senate
Document Control Number: EPA-HQ-OAR-2002-0058-2950
Comment Excerpt Number: 10

Comment: This is contrary to environmental and energy policies established by the state and federal government which promote the use of biomass boilers. It's good policy because dioxin/furan emissions are typically lower, there is no net increase in greenhouse gas emissions, and there is an abundance of biomass which is a renewable, domestic energy source.

Response: The carbon emissions from biomass are not within the scope of this rulemaking. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source, and see the preamble for the revised limits.

Commenter Name: John C. deRuyter
Commenter Affiliation: DuPont
Document Control Number: EPA-HQ-OAR-2002-0058-2793.1
Comment Excerpt Number: 10

Comment: Imposition of the proposed emission limits on units firing LFG will very likely result in a cessation of beneficial burning of LFG in boilers and process heaters for two reasons: first, and most importantly, there is no assurance that all emission limits can be achieved even with application of emissions control technology; and second, installation of emissions controls in an attempt to meet the proposed limits will be prohibitively expensive compared to simply stopping combustion of LFG and instead increase use of natural gas. Thus this proposed rule will stop the LMOP program in its tracks relative to use of LFG as boiler and process heater fuel; result in increased criteria pollutant emissions; and result in increased GHG emissions due to flaring of the LFG and alternative use of increased natural gas. DuPont instead recommends that EPA recognize the overall environmental benefits of using LFG and treat LFG as Gas 1 with use of a work practice standard approach.

Response: See the preamble for discussion of achievability of emission limits and how we modified the gas 1 subcategory to be more inclusive of other fuel types.

Commenter Name: David Bonistall
Commenter Affiliation: NewPage Corp
Document Control Number: EPA-HQ-OAR-2002-0058-2920.1
Comment Excerpt Number: 11

Comment: Without any adjustments to the proposed rule to better accommodate these combination boilers, the owners and/or operators of these boilers may have to switch away from biomass and burn more coal to be able to comply with the coal subcategory emission standards. This unintended consequence of replacing biomass with coal is contrary to national energy and climate policy, which encourages the use of more renewable biomass fuel.

Response: The emission limits are revised for the final rule, see the preamble for discussion. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source.

Commenter Name: Holly R. Hart
Commenter Affiliation: United Steelworkers Union
Document Control Number: EPA-HQ-OAR-2002-0058-2964.1
Comment Excerpt Number: 12

Comment: It is the policy of the United States to encourage the use of biomass fuels, and if EPA regulates these units via a MACT standard it will encourage the owners to switch to cheaper fuels such as coal, just as the agency reasons a MACT standard would encourage owners of boilers in the exempted categories to switch to such fuels as coal (75 Fed. Reg. 107, June 2, 2010, p. 32025). It also will substantially discourage operators from considering any switch to biogas as fuel, a switch otherwise encouraged by the government of the United States. EPA's consideration of these and related factors in deciding its regulatory approach is mandated by CAA Section 112 (d) (2).

Response: The carbon emissions from biomass are not within the scope of this rulemaking. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source, and see the preamble for the revised limits.

Commenter Name: Cathy S. Woollums
Commenter Affiliation: MidAmerican Energy Holdings Company
Document Control Number: EPA-HQ-OAR-2002-0058-2786.1

Comment Excerpt Number: 13

Comment: The EPA Should Establish a Limited Use Subcategory. Section 112(c)(1) of the Clean Air Act provides the EPA with the authority to establish subcategories of sources for which MACT standards are to be issued. Section 112(d)(1) states that EPA may distinguish among classes, types and sizes of sources within a category or subcategory in developing MACT standards. As such, the 2004 Boiler MACT provided for boiler subcatergorization based on limited use. Specifically, under this previous rulemaking, units with a capacity factor of less than 10% had less stringent emission limits (for solid fuel units) or limited initial notification reporting requirements (for gas and liquid units). This previous rulemaking appropriately recognized that limited use units require their own subcategory because of the unique characteristics of and functions provided by these boilers and process heaters. Specifically, limited use boilers and process heaters serve as emergency, back-up, or start-up units. These boilers and process heaters operate to fill in for a regular unit when that other unit is not operational. Other limited use boilers, such as auxiliary boilers at electric generating plants, only operate to provide steam to large boilers during start-up operations. These units inherently emit low levels of HAPs because of their limited use. MidAmerican believes EPA has the authority to provide for a limited use subcategory under this proposed Boiler MACT; the decision in the Brick MACT litigation (which resulted in the vacature of the previous Boiler MACT) did not specifically address the legality of limited use categorization. MidAmerican submits that the EPA should reestablish a limited use subcategory.

The limited use subcategory should be expanded to include units having annual capacity factors less than or equal to 25 percent. The previously proposed 10 percent capacity factor is too limiting and fails to account for many utility boilers that function as an emergency, back-up, or start up boiler but operate at capacity factors greater than 10 percent.

Response: EPA agrees and has created a limited use subcategory, see the preamble for discussion.

Commenter Name: Russ A. Wozniak
Commenter Affiliation: Dow Chemical Company
Document Control Number: EPA-HQ-OAR-2002-0058-2632.1
Comment Excerpt Number: 13

Comment: The rule is not clear if the proposed emission limits apply during <10% of maximum rated output operation. EPA should consider excluding stand-by operations from the proposed regulatory limits since the purpose of operating in this mode is to consume fuel at an absolute minimum (supporting energy and waste reduction initiatives) while being able to bring a steam boiler up to maximum capacity in a very short period of time in order to supply uninterrupted steam supply to manufacturing plants at larger integrated sites. It should also be noted that the boiler exhaust temperatures are much lower than design during these low load conditions such that an oxidation catalyst to reduce CO emissions will not be effective. Therefore, mandating a 1 ppmv CO level will require increased loads on stand-by boilers even if equipped with oxidation catalysts. This will result in increased energy consumption.

Regarding CO CEMS data, at a minimum EPA needs to exclude CO emissions requirements during periods when affected units are operated at less than 50% load as EPA had finalized in the original Boiler MACT standards in 2004. This exclusion will allow some relief for standby units. EPA should incentivize stand-by operation because this means that regulated entities have a better chance of minimizing malfunction related emissions elsewhere at their site if they have a boiler on stand-by, which can be ramped up on an as needed basis.

Response: See the preamble for discussion of CO limits.

Commenter Name: Leslie Sue Ritts
Commenter Affiliation: National Environmental Development Association's Clean Air Project NEDA/CAP
Document Control Number: EPA-HQ-OAR-2002-0058-2794.1
Comment Excerpt Number: 14

Comment: Until clean fuels are available across the country, and until the economy is strong enough to provide the capital investment for the use of such fuels, we predict a significant number of plant closures as a result of this rulemaking. We recommend a close examination of the effect of such closures on economic recovery.

Response: The limits for the final rule are revised and compliance options allow for greater flexibility for boiler operators. As such the economic impact should be reduced, see the preamble for further discussion.

Commenter Name: Holly R. Hart
Commenter Affiliation: United Steelworkers Union
Document Control Number: EPA-HQ-OAR-2002-0058-2964.1
Comment Excerpt Number: 15

Comment: It is the policy of the United States to promote the use of biomass energy. Not only is biomass renewable energy; it also, if managed properly throughout its fuel cycle, is carbon neutral. Among EPA’s obligations in CAA Section 112 (d) (2) is the requirement that it consider “non-air quality health and environmental impacts and energy requirements.”

The proposed rule as written will cause many biomass users that are able to stay in business to utilize natural gas boilers instead of biomass. The ongoing cost saving for doing so based on EPA’s own figures would be $609 million dollars per year or $1.45 million per year per boiler, a very substantial incentive. Natural gas is a fossil fuel. It is not renewable and it is not carbon neutral. In addition there are significant environmental and public issues health impacts connected with the technologies used for the drilling and extraction of the shale gas that will be needed if the proposed rule were to drive a large-scale switch to natural gas.

Response: The carbon emissions from biomass are not within the scope of this rulemaking. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source, and see the preamble for the revised limits.

Commenter Name: Christy Sammon
Commenter Affiliation: Southeast Lumber Manufacturers Association
Document Control Number: EPA-HQ-OAR-2002-0058-2727.1
Comment Excerpt Number: 18

Comment: The rules as proposed create a disincentive to the combustion of biomass and an incentive to burn natural gas.
The wood products industry uses a higher percentage of renewable energy than any other industry. The bark, sawdust, and other byproducts generated in the manufacturing process typically provide enough fuel to fire the boilers and meet the steam demands of the facility. The combustion of these biomass fuels is greenhouse-gas-neutral, and if these materials are not burned for fuel they will be hauled to a landfill where they will anaerobically decompose to methane gas which has 21 times the greenhouse gas impact of CO_2. Substituting a traditional fuel such as natural gas for this use will increase operating costs by as much as 30%, and if the entire wood products industry changed to natural gas, it would consume a significant percentage of the total U.S. natural gas production.

Response: The carbon emissions from biomass are not within the scope of this rulemaking. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source, and see the preamble for the revised limits.

Commenter Name: David Bonistall
Commenter Affiliation: NewPage Corp
Document Control Number: EPA-HQ-OAR-2002-0058-2920.1
Comment Excerpt Number: 31

Comment: The proposed Boiler MACT rule does not address the potential for the GHG PSD Tailoring Rule to impact projects needed to bring boiler units into compliance with the Boiler MACT standards. Due to the amount of uncertainty associated with the GHG Tailoring Rule we are requesting EPA categorically exempt projects required to comply with Boiler MACT from the GHG Tailoring Rule and GHG PSD requirements.

Addressing this uncertainty by exempting projects required to comply with Boiler MACT from the GHG Tailoring Rule and GHG PSD requirements is critical for the long term viability of U.S. manufacturing. Otherwise these rules have the consequence of putting U.S. companies at a competitive disadvantage in the global market place. As companies review compliance strategies, the relocation of U.S. production and the associated manufacturing jobs to countries that do not have to comply with Boiler MACT may be financially attractive and there will be far less uncertainty regarding these environmental regulatory requirements.

Response: Exemptions to the GHG PSD Tailoring rule are outside the scope of this rulemaking which establishes a set of MACT floor emission limits for air toxics, or surrogates for air toxics.

Commenter Name: David Bonistall
Commenter Affiliation: NewPage Corp
Document Control Number: EPA-HQ-OAR-2002-0058-2920.1
Comment Excerpt Number: 32

Comment: Compliance with Boiler MACT will require facilities to install extensive emission control equipment to meet the proposed Boiler MACT emission limits. Specifically, EPA stated in the preamble that emission control would likely require a fabric filter (FF) plus carbon injection plus wet scrubber control plus combustion improvements or carbon monoxide (CO) catalyst. The installation of this equipment could result in increases in emissions of GHGs and/or require modifications to existing air permits. Installation of additional control equipment may result in emission increases due to having to increase firing rates as a result of changes in pressure drops, increased fuel burning to meet increased electrical demand of additional control equipment, etc. In addition, facilities may be required to make operational changes in order to meet the Boiler MACT limits that could result in increases in emissions of GHGs due to fuel switching, etc. Changes to Title V air permits to address installation and operation of new control equipment may also be needed.

Response: See the preamble for discussion regarding control devices concerns.

Commenter Name: David P. Tenny
Commenter Affiliation: National Alliance of Forest Owners
Document Control Number: EPA-HQ-OAR-2002-0058-2750.1
Comment Excerpt Number: 11

Comment: NAFO is concerned that because the proposed rule's stringent, numeric emissions limitations for biomass units are largely unachievable, it would create a disincentive to the continued and expanded use of biomass fuels and, in turn, could encourage the use of higher-carbon fossil fuels. As described by Metso Power, the proposed rule would discourage, if not eliminate, new development of renewable biomass power. [See submittal for Attachment 1 at 2].

Response: The emission limits are revised for the final rule, see the preamble for discussion. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source.

Commenter Name: James Johnson
Commenter Affiliation: U.S. Beet Sugar Association
Document Control Number: EPA-HQ-OAR-2002-0058-2827.1
Comment Excerpt Number: 1

Comment: Sugarbeet processing is an energy intensive process. The energy is supplied by industrial boilers fired by coal, #6 fuel oil and natural gas. Fifty years ago, there were three times as many beet sugar factories operating in the U.S. as there are today. The twenty-two existing factories have been able to survive in large part due the energy efficiency improvements they have made.
The proposed rule, as written, has the potential to greatly impact operations at the sugarbeet processing facilities across the nation, which will result in significant costs, both for initial compliance as well as ongoing compliance. Existing operations will likely require significant physical modification in order to comply with the proposed rule requirements. Not only will this impact compliance with respect to this specific proposed rule, but may also have the result of triggering the review of additional rules, such as New Source Performance Standards and Prevention of Significant Deterioration Regulations as a result.

Response: See preamble for discussion on revised limits and biomass definition.

Commenter Name: Steven W. Koehn
Commenter Affiliation: National Association of State Foresters
Document Control Number: EPA-HQ-OAR-2002-0058-2860.1
Comment Excerpt Number: 1

Comment: NASF is concerned that the proposed Major Source rule will prevent new markets for forest biomass from developing. Unnecessarily stringent regulations in the proposed rule can be cost prohibitive and have the potential to prevent new investment in wood-based bioenergy facilities. This will cause boilers to increase their use of fossil fuels which runs counter to the nation's renewable energy goals. Further, lack of markets for biomass will increase onsite open burning which can have negative public health impacts such as the release of methane and black carbon. We strongly encourage EPA to avoid finalizing regulations that have unintended consequences that limits forest role in delaying the nation's shift to clean, renewable energy.
I. General Comments

Response: The emission limits are revised for the final rule, see the preamble for discussion. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source.

Commenter Name: Ronald Saff
Commenter Affiliation: Citizen
Document Control Number: EPA-HQ-OAR-2002-0058-3205
Comment Excerpt Number: 1

Comment: If these biomass plants are allowed to continue to be approved, the consequences will be massive deforestation and an increase in death, disease and cancer.

Response: EPA thanks the commenter for their input. Approval of permits for new biomass energy plants are outside the scope of this rulemaking and EPA has finalized emission limits for biomass units greater than or equal to 10 mmBtu/hr to be protective of human health and environment.

Commenter Name: Aubra Anthony, Jr
Commenter Affiliation: Anthony Forest Products Company
Document Control Number: EPA-HQ-OAR-2002-0058-2885.1
Comment Excerpt Number: 1

Comment: The wood products industry leads all other manufacturing industries in using renewable fuels. Industry group statistics show that in 2008, renewable fuels produced 73.5% of the needed energy at wood products facilities. U.S Department of Energy data show that wood products facilities, such as ours, produced 6% of the renewable fuel energy generated by all manufacturing facilities in all sectors.

To the determent of this industry and the nation's recent energy policies, new environmental regulatory proposals, such as the Non-Hazardous Secondary Materials Rule, the Standards of Performance for Commercial and Industrial Solid Waste Incinerators (CISWI), Boiler GACT, Greenhouse Gas Mandatory Reporting Rule (through the proposed Settlement Agreement No. 09-1333), among others, along with Boiler MACT threaten severe harm to our industry and our current renewable fuel usage strategies. This threat comes during one of the worst economic crisis ever seen by this country.

Response: The emission limits are revised for the final rule, see the preamble for discussion. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source.

Commenter Name: Robert C. Carroll
Commenter Affiliation: Renovar Energy Corp
Document Control Number: EPA-HQ-OAR-2002-0058-3183
Comment Excerpt Number: 1

Comment: We have received comments from our customers to the effect that the referenced proposed rule, the "Boiler MACT" rule, will discourage them from further utilization of landfill gas at their facilities. This rule would have the unintended consequence of essentially gutting the EPA's decades-long program to encourage the use of landfill gas as a renewable energy source.

Response: See the preamble for discussion of achievability of emission limits and how we modified the gas 1 subcategory to be more inclusive of other fuel types.

Commenter Name: Robert E. Cleaves
Commenter Affiliation: Biomass Power Association
Document Control Number: EPA-HQ-OAR-2002-0058-2934.1
Comment Excerpt Number: 1

Comment: In light of the overwhelming support for biomass from every corner of government[see submittal for Federal Agency support for biomass], it is imperative that EPA adopt a rule that is protective of the public health and the environment while also allowing this critically important energy source to be fully utilized.

Response: The emission limits are revised for the final rule, see the preamble for discussion. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source.

Commenter Name: Ted Sturdevant
Commenter Affiliation: Washington Department of Ecology
Document Control Number: EPA-HQ-OAR-2002-0058-2987.1
Comment Excerpt Number: 1

Comment: The NESHAP should ensure public health and environmental protection consistent with federal law. Further, EPA should set new source emission standards that help foster investment in cleaner, more efficient boiler systems that result in cleaner air, fewer greenhouse gas emissions and help stimulate the green energy economy. We ask EPA to review its proposed rule to limit the potential to create increased greenhouse emissions associated with increased fossil fuel combustion; and its potential impact on efforts to create markets or beneficial uses for organic materials previously seen as "waste."

Response: The emission limits are revised for the final rule, see the preamble for discussion. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source.

Commenter Name: Chris Korleski
Commenter Affiliation: Ohio EPA
Document Control Number: EPA-HQ-OAR-2002-0058-2818.1
Comment Excerpt Number: 1

Comment: The Ohio EPA finds the proposed rule to contain fundamental flaws, and as written, will cause unnecessary economic hardships to Ohio's industrial sector. We also believe the proposed rule creates a significant impediment to the development of clean and renewal fuels as alternatives for non-renewable fossil fuels.

Response: The limits for the final rule are revised and compliance options allow for greater flexibility for boiler operators. As such the economic impact should be reduced, see the preamble for further discussion. The topic of carbon neutrality is outside the scope of this rulemaking. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source.

Commenter Name: Terry Charles
Commenter Affiliation: Domtar Paper Company, LLC
Document Control Number: EPA-HQ-OAR-2002-0058-3182
Comment Excerpt Number: 1

Comment: Like so many in our industry, the Domtar mill in Rothschild, Wisconsin relies heavily on the combustion of biomass to control thermal energy costs. The proposed Boiler MACT standards threaten our future utilization of renewable biomass to produce steam for pulp and paper making.

Response: The emission limits are revised for the final rule, see the preamble for discussion. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source.

Commenter Name: Bill Perdue
Commenter Affiliation: American Home Furnishings Alliance
Document Control Number: EPA-HQ-OAR-2002-0058-2692.1
Comment Excerpt Number: 1

Comment: The wood furniture manufacturing industry uses kiln dried wood containing less than 20% moisture to generate the heat and steam necessary to manufacture our finished product. Our industry is one of the original recycling sectors in industrial manufacturing. Modern manufacturers achieve approximately 50% yield from sawmill wood stock. Rather than dispose of the remaining 50% dry wood biomass in a landfill, the biomass "off-fall" is beneficially used to produce energy. By combusting kiln dried wood in steam generating boilers, the wood furniture industry avoids the need to rely upon fossil fuels for process and domestic heating purposes. Combustion of our wood fuel also precludes land filling the wood off-fall, which would add environmental insult to the injury of being prevented from using a valuable fuel commodity.

Response: It is not our desire to preclude operators from burning biomass. The emission limits are revised for the final rule, see the preamble for discussion. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 for further discussion on biomass.

Commenter Name: Steven G. Hanson
Commenter Affiliation: Graphic Packaging International
Document Control Number: EPA-HQ-OAR-2002-0058-2723.1
Comment Excerpt Number: 1

Comment: While GPI operates existing boilers, GPI's Macon Mill is presently in the planning stages for installation of a new circulating fluidized bed boiler to combu st predominantly biomass, with natural gas and potentially tire-derived fuel (TDF) as auxiliary fuels. Installation of the new boiler will allow for the shutdown and/or removal of coal combustion from two 1940-era units at the Macon Mill. However, the proposed Boiler MACT jeopardizes GPI — Macon Mill's ability to move forward with this proposed installation, which would improve energy efficiency, reduce reliance on fossil fuel combustion sources, increase use of a renewable energy source, and result in an improved air emissions profile from the Macon Mill operations.

Response: The emission limits are revised for the final rule, see the preamble for discussion. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source.

Commenter Name: American Crystal Sugar Company and Michigan Sugar Company
Commenter Affiliation: Patricia Hansen and Steven Smock
Document Control Number: EPA-HQ-OAR-2002-0058-2970.1
Comment Excerpt Number: 1

Comment: The proposed rule, as written, has the potential to greatly impact operations at not only our facilities, but at every one of the twenty-two sugar beet processing facilities located throughout the United States, which will result in significant costs both for initial compliance as well as ongoing compliance.

Existing operations will likely require significant physical modification in order to comply with the proposed rule requirements. Not only will this impact compliance with respect to the proposed rule, but may have the result of triggering the review of additional rules, such as New Source Performance Standards and Prevention of Significant Deterioration Regulations.

Response: See preamble for discussion on revised limits and biomass definition.

Commenter Name: Steve Zika
Commenter Affiliation: Hampton Lumber Mills, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2817.1
Comment Excerpt Number: 1

Comment: These proposed rules appear to be in direct conflict with President Obama's goal to increase green energy, reduce our reliance on fossil fuels, and to foster sustainable manufacturing jobs within our own borders. The forest products industry is one of the most sustainable industries in the United States of America today, as we operate using environmentally certified timber that is immediately replanted after harvest for future generations. A lot of our lumber is exported to Asia, which is another objective of the current administration. Hampton has made great strides at modernizing our sawmills, reducing environmental emissions, and producing green power.

Response: The emission limits are revised for the final rule, see the preamble for discussion. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source.

Commenter Name: Joseph M. Cloutier
Commenter Affiliation: RE-Gen, LLC
Document Control Number: EPA-HQ-OAR-2002-0058-3211.1
Comment Excerpt Number: 1

Comment: RE-Gen is concerned that the EPA's proposed rules will:

Diminish our country's energy security

Affect our efforts to meet our nation's state Renewable Standard Portfolios

Response: The carbon emissions from biomass are not within the scope of this rulemaking. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source, and see the preamble for the revised limits.

Commenter Name: Arthur Blazer
Commenter Affiliation: Council of Western State Foresters
Document Control Number: EPA-HQ-OAR-2002-0058-2832.1
Comment Excerpt Number: 1

Comment: The forestry sector in the Western U.S. has been in transition for many years, and in some places is at or below critical industry infrastructure to support the necessary forest management practices to sustain healthy forests. Market options for small diameter, lower value products, and expanded renewable energy markets will help diversify existing forest industry and provide economical alternatives to achieve sustainable, healthy forests in our country.
For example, vast areas of federal, state and private forests in the Western U.S. are identified for fuels reduction that reduces wildfire risk to communities and protects critical forest resources. Large landscapes are being impacted by bark beetle; removing the hazard trees generates large volumes of wood materials that currently have few local options for value-added products. Options for local, small-scale energy uses such as heating school campuses, prisons, and greenhouse complexes are a cost effective way of utilizing the forest and manufacturing residues, while contributing to community and state renewable energy goals. Larger bioenergy facilities also have a role in the western landscape in the form of combined heat and power, industrial boilers, and community energy systems, and are currently one of the major producers of renewable energy for the United States.
The draft Area Source and Major Source Rules will directly impact the cost and viability of existing and new systems. Unfortunately, these rules potentially have the unintended consequence of providing no options for using forest residues other than slash pile burning in the forest. This option alone cannot provide our nation with the resources needed to maintain healthy forests and help meet renewable energy standards. Although the rulemaking process such as the MACT standards are not required to look at these trade-offs and the alternative fates, the reality is that clean burning of forest biomass in modern high efficiency biomass boilers creates many benefits for society beyond renewable energy because it reduces this alternative source of emissions while producing renewable energy.

Response: The emission limits are revised for the final rule, see the preamble for discussion. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source.

Commenter Name: Chris Welch
Commenter Affiliation: Colorado Springs Utilities
Document Control Number: EPA-HQ-OAR-2002-0058-2943.1
Comment Excerpt Number: 2

Comment: To meet these emissions limits would require extensive process modifications, installation of controls and additional costs to meet stack testing requirements. Initial analysis shows a more cost effective solution to be removal of these boilers from service, installation of flares and utilization of electricity from the nearby power plant. The disincentive to utilize these boilers created by the proposed rule would result in additional emissions since the biogas would be flared and additional fuel would be burned at the power plant, and would be contrary to the goals of this MACT and the Clean Air Act.

Response: See the preamble for discussion of achievability of emission limits, how we adjusted CO levels, and how we modified the gas 1 subcategory to be more inclusive of other fuel types.

Commenter Name: Linda Barnfather
Commenter Affiliation: Washington House of Representatives
Document Control Number: EPA-HQ-OAR-2002-0058-2852.1
Comment Excerpt Number: 2

Comment: As the state has invested in the renewable energy field, we have looked to the forest products sector to take a leadership role. In particular we have focused on renewable biomass power as an arena where we have a competitive advantage and an ability to increase distributed domestic power generation and utilization of previously wasted forestry resources.
A 2005 state biomass inventory found that as a state we are "blessed with a vast and diverse, annually renewable biomass, which although in places is presently utilized for energy, fertilizer and feed, in other places is still quite underutilized and capable of being a significant factor in bioenergy, biofuel, or bioproduct production." The inventory found that Washington State has an annual production of over 16.9 million dry tons of underutilized biomass which could be capable of creating 15.5 billion kWh of electrical energy, or almost 50% of the state's annual residential energy consumption. [Footnote: http://www.ecy.wa.gov/pubs/0507047.pdf]
This focus on biomass power has resulted in significant levels of public and private investment.

Response: See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source.

Commenter Name: Mick Baranko
Commenter Affiliation: Douglas County Forest Products
Document Control Number: EPA-HQ-OAR-2002-0058-2856.1
Comment Excerpt Number: 2

Comment: Overly burdensome regulation will also result in similar increases in greenhouse gas emissions. The definitive study assessing the use of biomass to generate electricity is the May 2008 report entitled Bioenergy and Greenhouse Gases, prepared by Gregory Morris, PhD of The Renewable Energy Program of the Pacific Institute in Berkeley, California. This report notes that the use of biomass avoids the need to combust fossil fuels and also notes that because the combustion of biomass adds no net new carbon to the atmospheric-biospheric circulation system, it is considered "carbon neutral." Additionally, the study went beyond these comparatively simplistic conclusions to evaluate whether and how the change in terrestrial biomass (i.e., forest thinning) affects overall sequestration as well as the impacts of the change in timing and mix of carbon forms that occur depending on the fate of biomass. This detailed analysis concludes that greenhouse gas sequestration is enhanced by the forest thinning that generates much slash. Of greater importance, however, is the benefit achieved by avoiding open burning and/or decomposition (composting) of slash. Open burning and low-efficiency combustion (i.e., fireplaces) result in much higher emissions of methane, a potent greenhouse gas, as compared to controlled combustion in a boiler such as SSE's. Biomass that is left to decompose in the forest or is landfilled degrades into a 50-50 mixture of methane (C114) and carbon dioxide (CO_2). The report notes that due to the much higher global warming potential of methane, as compared to carbon dioxide, the global warming impacts associated with decomposition exceed those of controlled combustion even though less carbon is released into the atmosphere from natural decomposition over a 100-year period. In summary, Dr. Morris' team concluded that for every ton of biomass combusted to make electricity, you avoid 0.8 tons of greenhouse gas (CO2equivalent) as a result of avoided fossil fuel use. For the biomass originating as slash, there is an additional net reduction of greenhouse gases of between 0.22 tons and 2.28 tons, depending on how the slash would have been handled if it had not been routed to controlled combustion. [Reference: Morris; Bioenergy and Greenhouse Gases, Table 4, Green Power Institute of The Renewable Energy Program of the Pacific Institute, May 2008]. This means that by combusting biomass our facilities reduce GHGs by 1.42 tons for every bone dry ton of slash that they combust.

Response: The EPA did not have ample time or data to analyze the potential impacts the rule may have on open burning. However, the emission limits are revised for the final rule, see the preamble for discussion. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source.

Commenter Name: Bruce Coffee
Commenter Affiliation: Hurst Boiler and Welding Co
Document Control Number: EPA-HQ-OAR-2002-0058-2705.1
Comment Excerpt Number: 2

Comment: These actions will greatly increase the growth in demand for Natural Gas, a fossil fuel. In spite of the fuel crisis of a couple of year ago, and the Enron Crisis of a decade ago, this action will have the unintended consequence of driving more energy control into the hands of a few. From recent experience, we know that the price of Natural Gas can "sky-rocket" and catch companies mid-stream and drive many to bankruptcy. This is certain.

Response: EPA recognizes that the situation of each affected entity is different, and although some facilities may opt to switch to natural gas in lieu of biomass combustion, the data show that many biomass facilities are at or below the final emission limits. This suggests that many facilities will adopt biomass fuel specifications or install controls in order to meet the emission limits. Furthermore, EPA has determined that changes from the proposal have reduced economic impact on many biomass facilities; see the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 for further discussion on biomass.

Commenter Name: Dan F. Hunter
Commenter Affiliation: ConocoPhillips Company
Document Control Number: EPA-HQ-OAR-2002-0058-2867.1

Comment Excerpt Number: 2

Comment: We know of no means of simultaneously controlling gas-fired units to these levels.

Response: See the preamble for discussion of achievability of emission limits, how we adjusted CO levels, and how we modified the gas 1 subcategory to be more inclusive of other fuel types.

Commenter Name: Scott Manley
Commenter Affiliation: Wisconsin Manufacturers and Commerce
Document Control Number: EPA-HQ-OAR-2002-0058-2933.1
Comment Excerpt Number: 2

Comment: The severity of the proposed standards may lead to the perverse effect of providing disincentives against moving forward with projects that otherwise would result in environmental improvements.

Response: The emission limits are revised for the final rule, see the preamble for discussion. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source.

Commenter Name: Allyn Ford
Commenter Affiliation: Roseburg Forest Products
Document Control Number: EPA-HQ-OAR-2002-0058-3163
Comment Excerpt Number: 2

Comment: This proposed rule seems in direct conflict with the Administration's stated goal to increase the amount of greener, cleaner and sustainable energy generated within our own borders. Specifically, the rule will have a significant, negative impact on biomass fueled facilities. This rule will penalize biomass units because they start with a cleaner fuel; specifically when the inlet concentration of a pollutant is low (as is the case with biomass), it becomes exponentially more expensive to remove those concentrations and difficult to prove removal at the outlet (when outlet concentrations are below the analytical detection limit).

The rule will subject all biomass units to emission standards that are based on the very best performing, new biomass units. However, not even those best performing units can meet the proposed limits 100% of the time, nor do the best performing units comply with all the emission standards simultaneously, resulting in a standard that is unachievable. Rather than encouraging biomass generated power, this rule will have the opposite effect. When one compares the standards set forth in the rule for fossil fuel fired natural gas units versus biomass, it would be logical for investors to shy away from green, carbon neutral biomass fired units in favor of natural gas, fossil fuel-fired units. Yet, we know that natural gas and other fossil fuels are irreplaceable, unlike biomass which can be regrown.

Response: The emission limits are revised for the final rule, see the preamble for discussion. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source.

Commenter Name: Russell Wanke
Commenter Affiliation: Thilmany Papers
Document Control Number: EPA-HQ-OAR-2002-0058-3185.1
Comment Excerpt Number: 2

Comment: Our employees primarily heat their homes with natural gas, as does much of the Midwest. If these rules force industrial boilers to convert to using natural gas, prices for natural gas will skyrocket from the increased demand. This creates a double hit for citizens in the Midwest...loss of jobs in these manufacturing states and higher living expenses.

Response: Although some facilities may opt to switch to natural gas in lieu of biomass combustion, the data show that many biomass facilities are at or below the final emission limits. This suggests that many facilities will adopt biomass fuel specifications or install controls in order to meet the emission limits.

Commenter Name: Al Hankins, Jr.
Commenter Affiliation: Hankins Lumber Company, LLC
Document Control Number: EPA-HQ-OAR-2002-0058-2708.1
Comment Excerpt Number: 2

Comment: Our alternatives to complying with the major source rule are not at all advantageous, efficient or affordable either. One alternative to huge investments in control equipment is to deliberately reduce our allowable production capacity to a level that would make us a non-major HAP source, but also non-competitive once the market picks up. We would then be subject only to the area source rules, that may prove to also be very expensive for us also. Other alternatives are not much better, but would include major changes in the processes for the sake of eliminating boilers at our site altogether. Again, we are talking about extremely expensive propositions in a down economy.

Response: See the preamble for discussion on revised limits.

Commenter Name: Catherine W. McCuthen
Commenter Affiliation: Blue Heron Paper Company
Document Control Number: EPA-HQ-OAR-2002-0058-2892.1
Comment Excerpt Number: 2

Comment: We respect EPA's job is to protect air quality. However, the existence of biomass boilers to receive woody material means that hundreds of thousands of tons of forest slash and/or wood residuals from sawmills is burned in controlled combustion rather than in open burn piles. As EPA research has previously established, routing biomass to boilers has a profound beneficial impact on hazardous air pollutant emissions. For example, in its paper published by Paul Lemieux of EPA's National Risk Management Research Laboratory, benzene emissions from the open burning of Douglas fir slash was estimated at 196 mg/kg. [Reference: Lemieux et al, Emissions of Organic Air Toxics from Open Burning: A Comprehensive Review; Table 6; Progress in Energy and Combustion Science 30 (2004)] The estimated benzene emissions from the controlled burning of Douglas fir slash in a biomass boiler is less than 5 mg/kg. This means that every ton of slash burned in the forest results in approximately 40 times more benzene than had that same ton been burned in a biomass boiler. By adding unduly burdensome regulations that force wood products companies or integrated papermills such as ours to stop burning biomass, EPA will cause the diversion of wood residues to open burning with the net result being a significant increase in hazardous air pollutant emissions or to landfills.

Response: The EPA thanks the commenter for their input, but the EPA did not have ample time or data to analyze the potential impacts the rule may have on open burning.

Commenter Name: Nina E. Butler
Commenter Affiliation: Smurfit-Stone Container Corp.
Document Control Number: EPA-HQ-OAR-2002-0058-2783.1
Comment Excerpt Number: 2

Comment: EPA has established emissions limits for biomass units that are so extremely stringent they are likely to discourage the use of renewable, carbon-neutral biomass fuels;

Response: The emission limits are revised for the final rule, see the preamble for discussion. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source.

Commenter Name: Catherine W. McCuthen
Commenter Affiliation: Blue Heron Paper Company
Document Control Number: EPA-HQ-OAR-2002-0058-2892.1
Comment Excerpt Number: 3

Comment: Overly burdensome regulation will also result in similar increases in greenhouse gas emissions. The definitive study assessing the use of biomass to generate electricity is the May 2008 report entitled Bioenergy and Greenhouse Gases, prepared by Gregory Morris, PhD of The Renewable Energy Program of the Pacific Institute in Berkeley, California. This report notes that the use of biomass avoids the need to combust fossil fuels and also notes that because the combustion of biomass adds no net new carbon to the atmospheric-biospheric circulation system, it is considered “carbon neutral.” Additionally, the study went beyond these comparatively simplistic conclusions to evaluate whether and how the change in terrestrial biomass (i.e., forest thinning) affects overall sequestration as well as the impacts of the change in timing and mix of carbon forms that occur depending on the fate of biomass. This detailed analysis concludes that greenhouse gas sequestration is enhanced by the forest thinning that generates much slash. Of greater importance, however, is the benefit achieved by avoiding open burning and/or decomposition (composting) of slash. Open burning and low-efficiency combustion (i.e., fireplaces) result in much higher emissions of methane, a potent greenhouse gas, as compared to controlled combustion in a boiler such as ours. Biomass that is left to decompose in the forest or is landfilled degrades into a 50-50 mixture of methane (CH_4) and carbon dioxide (CO_2). The report notes that due to the much higher global warming potential of methane, as compared to carbon dioxide, the global warming impacts associated with decomposition exceed those of controlled combustion even though less carbon is released into the atmosphere from natural decomposition over a 100-year period. In summary, Dr. Morris’ team concluded that for every ton of biomass combusted to make electricity, you avoid 0.8 tons of greenhouse gas (CO_2-equivalent) as a result of avoided fossil fuel use. For the biomass originating as slash, there is an additional net reduction of greenhouse gases of between 0.22 tons and 2.28 tons, depending on how the slash would have been handled if it had not been routed to controlled combustion. [Reference: Morris; Bioenergy and Greenhouse Gases, Table 4, Green Power Institute of The Renewable Energy Program of the Pacific Institute, May 2008]. This means that by combusting biomass our facilities reduce GHGs by 1.42 tons for every bone dry ton of slash that they combust.

Therefore, we strongly urge EPA to consider the comments below on how to revise the Boiler and Process Heater NESHAP so as to minimize the potential for boiler closures. It is not economical to haul biomass long distances. The elimination of biomass fuel in our boiler will have the immediate impact of increasing the amount of biomass that is disposed of through open burning and/or landfilling. This will have the exact opposite effect that EPA is hoping for through promulgation of the NESHAP.

Response: The EPA did not have ample time or data to analyze the potential impacts the rule may have on open burning. However, the emission limits are revised for the final rule, see the preamble for discussion. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source.

Commenter Name: Bruce A. Steiner
Commenter Affiliation: American Coke and Coal Chemicals Institute
Document Control Number: EPA-HQ-OAR-2002-0058-2849.1
Comment Excerpt Number: 3

Comment: Importantly, efforts made to switch from flaring coke oven gas or other process gases to combusting it in the more carefully controlled setting of a boiler will also benefit the environment in two ways. First, it will reduce the potential for inefficient combustion at the flare, which is exposed to wind and other elements that may interfere with complete combustion. Also, supplemental fuel at a flare is typically limited to the pilot light and is not available to help ensure a stable flame. As a result, EPA's emission factors assume up to 98% control of organic compounds from flares combusting gases with the heat values characteristic of coke oven gas. See EPA, AP-42 at 13.5-4 (citing EPA's Flare Efficiency Study, EPA-600/2-83-052). By contrast, properly tuned boilers achieve 99.9% combustion efficiency for organic compounds from gaseous fuels. See EPA, AP-42 at 1.4-3. This means that flares would be expected to emit 20 times the organic compounds that would be emitted from a boiler. Second, energy recovery in boilers will supplant the need for combustion of additional fossil fuels, thus eliminating the greenhouse gases, criteria pollutants, and HAP emissions associated with those fuels. For example, a 545 MMBTU/hr coke oven gas-fired boiler generating electricity will supplant 334,310 megawatt-hours of electricity previously purchased from the grid and reduce coal combustion by 260,000 tons per year. This one coke oven gas-fired boiler would reduce 357,240 tons of carbon dioxide emissions each year and many additional tons of other pollutants of concern.

Response: See the preamble for discussion of achievability of emission limits and how we modified the gas 1 subcategory to be more inclusive of other fuel types.

Commenter Name: Joseph M. Cloutier
Commenter Affiliation: RE-Gen, LLC
Document Control Number: EPA-HQ-OAR-2002-0058-3211.1
Comment Excerpt Number: 3

Comment: RE-Gen is concerned that the EPA's proposed rules will:

Derail the effort to strengthen the health of our forests and agricultural lands

Distract our fight to better climate change

Response: The emission limits are revised for the final rule, see the preamble for discussion. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source.

Commenter Name: David P. Tenny
Commenter Affiliation: National Alliance of Forest Owners
Document Control Number: EPA-HQ-OAR-2002-0058-2750.1
Comment Excerpt Number: 3

Comment: Forests can play an important role in reducing and managing greenhouse gas emissions. Expanding the sources of renewable energy is a central feature of both national and international policy to reduce reliance on fossil fuels.

The EPA, in considering approaches toward addressing climate change, has long recognized that responsibly managed forests are considered one of five key “groups of strategies that could substantially reduce emissions between now and 2030.” See Regulating Greenhouse Gas Emissions Under the CAA, 73 Fed. Reg. 44,354, 44,405 (July 30, 2008). Similarly, the United Nation’s Intergovernmental Panel on Climate Change (“IPCC”) report on mitigation technologies highlights forest management as a primary tool to reduce GHG emissions. Id. at 44,405-06; see also NAFO, Carbon Mitigation Benefits of Working Forests (identifying trading platforms and registries that recognize forest management), available at http://nafoalliance.org/mitigation-benefits-working-forests/.

President Obama has emphasized that renewable energy derived from feedstocks such as forest biomass hold the key to transitioning the nation to a “sustainable, low carbon energy future.” See Letter from President Barack Obama to Governors John Hoeven and Chet Culver (May 27, 2009), available at http://www.governorsbiofuelscoalition.org/assets/files/President%20Obama’s%20Respo nse5-27-09.pdf; see also President Barack Obama, Memorandum for the Secretary of Agriculture, the Secretary of Energy, and the Administrator of the Environmental Protection Agency, 74 Fed. Reg. 21531-32 (May 5, 2009).

With Presidential endorsement, if not direction, of national renewable energy policy and the role of biomass in that policy, EPA must conduct its programs in a manner consistent with that policy. In light of this policy, EPA must not adopt any mandatory environmental controls, such as those set forth in the proposed rulemaking, that will require large expenditures of time and resources by industry, but are not necessary to protect human health and the environment. Similarly, to act consistently with this nation’s renewable energy policy, EPA must not impose restrictions on biomass boilers that are not legally required and that stand to disadvantage the use of biomass as a fuel source. The proposed rule lacks any justification for its departure from this policy and, as explained below, is thus arbitrary and capricious.

Response: See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source.

Commenter Name: Christopher S. Bond
Commenter Affiliation: United States Senator
Document Control Number: EPA-HQ-OAR-2002-0058-2958.1
Comment Excerpt Number: 3

Comment: EPA’s imposition of standards so expensive that they force forest-product facilities to abandon their use of biomass to power their operations would drive those that survive to more carbon-intensive energy sources such as coal, predominant in Missouri, or propane. Not only would facilities release more carbon from their energy sources, but the carbon from the biomass byproduct would still be released into the atmosphere after it is discarded. Thus, EPA’s proposal threatens both the administration’s goal of encouraging renewable, lower-carbon fuels and reducing carbon emissions.

Response: The emission limits are revised for the final rule, see the preamble for discussion. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source.

Commenter Name: Michael Potter
Commenter Affiliation: Goodyear Tire and Rubber Company
Document Control Number: EPA-HQ-OAR-2002-0058-3181
Comment Excerpt Number: 3

Comment: Goodyear believes that promulgation of the proposed rules will greatly increase the usage of natural gas in the regulated boilers, straining the availability of natural gas and thereby significantly increasing the frequency, duration and severity of natural gas curtailments and supply interruptions in the future. Other possible future EPA regulations, such as regulations related to greenhouse gas emissions, could exacerbate this situation even further. Because Goodyear cannot predict the timing or duration of gas curtailments and interruptions at its various plant locations, and cannot predict what enforcement actions EPA or State Agencies may take in response to notifications submitted under section 63.7545(f), the proposed regulations may require Goodyear to install exorbitantly costly emission control systems to meet oil subcategory standards just to protect plant operations from possible disastrous production curtailments. This enormous investment might be needed just to preserve existing fuel oil back up capabilities even though the controls may seldom be used, if ever.

Response: EPA is not requiring fuel switching to natural gas in the final rule. Further, based on the data from best performing units in the biomass subcategory several units firing biomass are meeting the final emission limits. Therefore, EPA does not expect all of the units firing biomass to switch to natural gas as a compliance option and increased natural gas usage will be minimal. Also note that emission limits for oil boilers have been revised, see the preamble for discussion.

Commenter Name: Joe Muehlbach
Commenter Affiliation: Quad/Graphics
Document Control Number: EPA-HQ-OAR-2002-0058-2898.1
Comment Excerpt Number: 3

Comment: This broad, "hypothetical boiler" approach that EPA is proposing will also have another unintended consequence: it will provide a significant disincentive for conversion of existing coal-fired boilers to renewable energy fuels such as biomass. The anticipated cost for compliance for biomass boilers under the proposed approach to a MACT standard will likely be prohibitive for anyone considering such a renewable energy conversion project.

Response: The emission limits are revised for the final rule, see the preamble for discussion. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source.

Commenter Name: Tim Hagley
Commenter Affiliation: Minnesota Power
Document Control Number: EPA-HQ-OAR-2002-0058-2829.1
Comment Excerpt Number: 3

Comment: Essentially, the rule, if finalized, would prevent the co-firing of biomass in our boilers, resulting in 100 percent coal combustion to support steam production for mill operation. The waste wood fuel supply currently being utilized would likely need to be landfilled. Clearly, the environmental implications of this could be very significant, resulting in greater use of fossil fuels while filling up landfills at a greater pace. This is not consistent with national and state environmental policy.

Response: See the preamble for new subcategory definitions and revised emission limits.

Commenter Name: Mick Baranko
Commenter Affiliation: Douglas County Forest Products
Document Control Number: EPA-HQ-OAR-2002-0058-2856.1
Comment Excerpt Number: 3

Comment: We strongly urge EPA to consider the comments below on how to revise the Boiler and Process Heater NESHAP so as to minimize the potential for boiler closures. It is not economical to haul biomass long distances. The closure of one of our boilers will have the immediate impact of increasing the amount of biomass that is disposed of through open burning and/or landfilling This will have the exact opposite effect that EPA is hoping for through promulgation of the NESHAP.

Response: The emission limits are revised for the final rule, see the preamble for discussion. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source.

Commenter Name: Mary L. Frontczak
Commenter Affiliation: Peabody Energy
Document Control Number: EPA-HQ-OAR-2002-0058-2897.1
Comment Excerpt Number: 4

Comment: EPA’s discrimination against coal will evidently have its desired effect. EPA projects that "... the majority of new boilers and process heaters will be built to fire natural gas as opposed to solid and liquid fuels." According to the Agency, no new coal-fueled units will be built in the next three years, while 33 new natural gas/refinery gas units will be built. Fuel switching caused by the Boiler MACT rule will increase natural gas demand by .65 TCF to .85

TCF in a relatively short time period and will bring the country to a level of natural gas demand that EIA has not forecast until 2025.

Response: It is necessary to note that the limits of this rule were not a factor in projecting the number of new major source units. Rather, projections were based on the economic outlook of the energy sector.

Commenter Name: Christopher Peters
Commenter Affiliation: Low Carbon Synthetic Fuels Association
Document Control Number: EPA-HQ-OAR-2002-0058-2942.1
Comment Excerpt Number: 4

Comment: Continued categorization of syngas under the Gas 2 subcategory would result in unintended consequences by encouraging the use of natural gas to the exclusion of all other fuels, no matter how environmentally friendly, because regulatory requirements for natural gas-fired boilers would be much more favorable and less administratively burdensome. As EPA has used this rulemaking as an opportunity to assess the energy efficiency of boilers, we believe excluding the efficiency gains that could be achieved through integrated biorefineries would be inconsistent with the intent of the proposal.

Response: See the preamble for discussion of achievability of emission limits and how we modified the gas 1 subcategory to be more inclusive of other fuel types.

Commenter Name: Bill Perdue
Commenter Affiliation: American Home Furnishings Alliance
Document Control Number: EPA-HQ-OAR-2002-0058-2692.1
Comment Excerpt Number: 4

Comment: There has been considerable discussion regarding the classification of biomass as a carbon-neutral fuel. The carbon neutral classification of biomass will not be settled in this forum. However, we can definitively assert that the proposed rule will reduce or eliminate the use of dry biomass fuel in the wood furniture manufacturing industry, and a significant portion of the displaced fuel source will be replaced by fossil fuels such as natural gas or coal. It is wrong to argue that replacement of biomass fuel with fossil fuels would not increase GHG emissions.

Response: The carbon emissions from biomass are not within the scope of this rulemaking. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source, and see the preamble for the revised limits.

Commenter Name: Edward E. Quick

Commenter Affiliation: Celanese International Corp
Document Control Number: EPA-HQ-OAR-2002-0058-2840.1
Comment Excerpt Number: 4

Comment: EPA should exercise its discretion to establish health based emission limits (HBEL). The unintended consequences that HCl controls may prevent recycling of combustion wastes. Coal ash from uncontrolled coal combustion sources is desirable for recycling in the cement manufacturing industry. In many instances, wet scrubbers will change the characteristics of this waste, making recycling infeasible.

Response: A health based compliance option is not provided, see the preamble for discussion.

Commenter Name: Bruce A. Steiner
Commenter Affiliation: American Coke and Coal Chemicals Institute
Document Control Number: EPA-HQ-OAR-2002-0058-2849.1
Comment Excerpt Number: 4

Comment: If EPA finalizes a rule that subjects coke oven gas-fired boilers to the stringent numeric emissions limitations proposed for Gas 2 sources, the additional cost of controls would functionally eliminate these valuable efforts to reclaim energy. The U.S. Department of Energy has awarded competitive grant funds to energy recovery projects that convert flared coke oven gas to usable steam and electricity. The Proposed Rule would discourage the type of energy recovery project that DOE is actively trying to promote. This is because the annualized cost of control required to meet the Gas 2 emission limits exceeds the cost of replacement natural gas for many units. Facing this economic reality, coke oven gas will be flared and natural gas will be combusted to generate steam to the detriment of the environment and our national goals of energy independence.

Response: See the preamble for discussion of achievability of emission limits and how we modified the gas 1 subcategory to be more inclusive of other fuel types.

Commenter Name: Dan F. Hunter
Commenter Affiliation: ConocoPhillips Company
Document Control Number: EPA-HQ-OAR-2002-0058-2867.1
Comment Excerpt Number: 4

Comment: The low CO alternate emission limit would have the effect of raising other pollutants, including NOx, CO_2 and HAP (the very pollutant statutorily targeted for reduction) because inefficient operation of units at this low CO level will require more fuel to be burned for the same heat output. Additionally, other surmised control measures would require increased energy to operate, require significant space requirements, potential demolition costs and facility process shutdowns. In fact, the very projects needed to install such controls would likely emit more emissions that could be reduced over the life of the equipment for gas-fired sources. Such factors have apparently not been considered by EPA.

Response: See the preamble for discussion on CO limits.

Commenter Name: Linda Barnfather
Commenter Affiliation: Washington House of Representatives
Document Control Number: EPA-HQ-OAR-2002-0058-2852.1
Comment Excerpt Number: 4

Comment: The state has pursued policy opportunities to promote long term stability and investment in the biomass industry. The state passed a law in 2010 allowing for long term contracts for biomass purchase from state timber lands. In addition to providing stability to the industry, our state DNR anticipates additional revenues from forest residuals to be a benefit to the common school trust fund. In recent years the state has provided tax incentives for hog fuel and biomass energy, authorized county governments to acquire biomass generation facilities, and ensured that our greenhouse gas policies reflect our priorities in this area.
We have heard credible concerns from the affected industries in our state that the current rules promote unattainable standards that will seriously endanger the viability of these businesses and all the progress we have made to date.

Response: The emission limits are revised for the final rule, see the preamble for discussion. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source.

Commenter Name: Bruce Coffee
Commenter Affiliation: Hurst Boiler and Welding Co
Document Control Number: EPA-HQ-OAR-2002-0058-2705.1
Comment Excerpt Number: 4

Comment: At a time when we should be increasing our sustainability by decreasing our dependence on fossil fuels, this is a major step backwards for the country. This will have a detrimental effect on development of the very fuels we need to use most to slow the flow of wastes into our landfills.

Response: The emission limits are revised for the final rule, see the preamble for discussion. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source.

Commenter Name: Joseph M. Cloutier

Commenter Affiliation: RE-Gen, LLC
Document Control Number: EPA-HQ-OAR-2002-0058-3211.1
Comment Excerpt Number: 4

Comment: We are especially concerned that the proposed changes make take affect as the Administration's support of biomass has been unwavering and involves almost every member of the Cabinet from the White House, USDA, DOE, Interior, Council on Environment Quality, EPA, DOJ, Treasury and Commerce. As well, in Congress biomass has been included in every single piece of renewable energy legislation beginning with the Public Utility Policy Act of 1978. Support for biomass is universal, bi-partisan, and spans the scope of virtually every major energy policy enacted by the Congress.

RE-Gen urges, in light of the overwhelming support for biomass from every corner of government, that EPA adopt a rule that provides flexible approaches that appropriately address the diversity of boilers, operations, sectors, and fuels that could prevent severe job losses and countless dollars in unnecessary regulatory costs. In this regard, we ask you to consider three particular issues as presented by The Biomass Power Association on August 23, 2010.

Response: See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source.

Commenter Name: Martha E. Rudolph
Commenter Affiliation: State of Colorado
Document Control Number: EPA-HQ-OAR-2002-0058-2940.1
Comment Excerpt Number: 5

Comment: EPA should not overlook possible deleterious environmental effects of new regulations that overly constrain existing and emerging technologies that use woody biomass for the production of renewable energy and other purposes. As Governor Ritter and the Western Governors' Association have repeatedly communicated, Colorado and the Inter-mountain West face forest health problems of monumental proportion. Landscape-scale insect infestations, disease, decades of fire suppression, and persistent drought have left Colorado forests in a state of elevated risk for catastrophic wildfire. Not only do such
intense fires compromise ecological health and watershed functionality, they pose risk for people, their communities and public infrastructure located within or adjacent to forested land. Importantly, they also are sources of PM, CO_2, CO, NOx, S02, and other pollutants in amounts and concentrations that dwarf emissions typically associated with biomass boilers and other means of controlled combustion of woody biomass. Since public financial resources are insufficient to underwrite large scale hazardous fuels reduction and forest thinning projects that are critical to reducing these risks and to restoring forested landscapes to healthier conditions within generally accepted ranges of natural variability, private investment tied to the potentially profitable use of woody biomass is a vital public policy objective. Unfortunately, more stringent air quality standards, if not clearly warranted from a public health standpoint, could dramatically impact the ability of private operators and local communities to use locally harvested materials

for heating or small scale power generation since the cost of the advanced control technologies are, in many instances, more expensive than the entire project. EPA should thus take a very rigorous look at whether, and if so in what instances, woody biomass should be included in, or excluded from, these proposed rules.
To further underscore the importance of the role of woody biomass use in managing Colorado's forest health issues, see the submittal for the August 10, 2010 letter from Governor Ritter to the U.S. Secretary of Agriculture, Thomas Vilsack.

Response: See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source.

Commenter Name: Douglas A. McWilliams
Commenter Affiliation: ArcelorMittal USA, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2811.1
Comment Excerpt Number: 5

Comment: Importantly, efforts made to switch from flaring coke oven gas to combusting it in the more carefully controlled setting of a boiler will also benefit the environment in two ways. First, it will reduce the potential for inefficient combustion at the flare, which is exposed to wind and other elements that may interfere with complete combustion. As a result, EPA's emission factors assume just 98% control of organic compounds from flares combusting gases with the heat values characteristic of coke oven gas. See EPA, AP-42 at 13.5-4 (citing EPA's Flare Efficiency Study, EPA-600/2-83-052). By contrast, properly tuned boilers achieve at least 99.9% combustion efficiency for organic compounds from gaseous fuels. See EPA, AP-42 at 1.4-3. Based on these EPA emission factors, flares would be expected to emit 20 times the organic compounds that would be emitted from a boiler. Second, energy recovery in boilers will supplant the need for combustion of additional fossil fuels, thus eliminating the greenhouse gases, criteria pollutants and HAP emissions associated with those fuels. For example, 545 MMBtu/hr coke oven gas-fired boiler generating electricity will supplant 334,310 megawatt hours of electricity previously purchased from the grid and offset 260,000 tons of coal combustion per year. This one coke oven gas-fired boiler would reduce 357,240 tons of CO_2 emissions annually and many additional tons of other pollutants of concern.

If EPA finalizes a rule that subjects coke oven gas-fired boilers to the stringent numeric emissions limitations proposed for Gas-2 sources, the additional cost of controls would functionally eliminate these valuable efforts to reclaim energy. The U.S. Department of Energy has awarded competitive grant funds to energy recovery projects that convert flared coke oven gas to usable steam and electricity. The Boiler MACT rule as proposed would discourage the type of energy recovery project that DOE is actively trying to promote. This is because the annualized cost of control required to meet the Gas-2 emission limits exceeds the cost of replacement natural gas for many units. Facing this economic reality, coke oven gas will be flared and natural gas will be combusted to generate steam to the detriment of the environment and our national goals of energy independence.

Response: See the preamble for discussion of achievability of emission limits and how we modified the gas 1 subcategory to be more inclusive of other fuel types.

Commenter Name: Steven G. Hanson
Commenter Affiliation: Graphic Packaging International
Document Control Number: EPA-HQ-OAR-2002-0058-2723.1
Comment Excerpt Number: 5

Comment: EPA has clearly established a disincentive for installation of new biomass boilers, which conflicts with the Obama administration's and Congress' intention to move towards greater renewable energy usage and reduction in fossil fuel usage. By establishing new source limits that are not realistically achievable by a new emission unit, EPA is promoting the reliance on older, less efficient energy/steam generating sources as well as units with emission profiles that are generally worse than new units. It is unlikely that this was the Congressional intent when establishing the requirements of CAA Section 112.

Response: The emission limits are revised for the final rule, see the preamble for discussion. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source.

Commenter Name: Kevin M. Dempsey
Commenter Affiliation: American Iron and Steel Institute
Document Control Number: EPA-HQ-OAR-2002-0058-2998.1
Comment Excerpt Number: 5

Comment: If EPA finalizes a rule that subjects coke oven gas-fired boilers to the stringent numeric emissions limitations proposed for Gas 2 sources, the additional cost of controls would functionally eliminate these valuable efforts to reclaim energy. The U.S. Department of Energy has awarded competitive grant funds to energy recovery projects that convert flared coke oven gas to usable steam and electricity. The Proposed Rule would discourage the type of energy recovery project that DOE is actively trying to promote. This is because the annualized cost of control required to meet the Gas 2 emission limits exceeds the cost of replacement natural gas for many units. Facing this economic reality, coke oven gas will be flared and natural gas will be combusted to generate steam to the detriment of the environment and our national goals of energy independence.

The economic analysis is clear. The Proposed Rule sets numeric emission limits for 5 pollutants (PM, HCl, Hg, dioxin/furans, and CO). At this time, coke oven gas-fired units are not controlled for these compounds. Using EPA's projected cost of control (annualized capital cost plus annual operating cost) for each pollutant, including monitoring, recordkeeping and reporting, an AISI member company has calculated an annualized cost of control at $8.6 million for a single 650 MMBTU/hr unit combusting coke oven gas. [The capital cost for the unit is $27,747,000 and the annual non-capital cost is $5,678,000.] At a natural gas cost of $5/MMBTU (costs have been much higher in recent years), it is economically unreasonable for the boiler operator to use coke oven gas to displace the first 1,720,000 MMBTU per year of natural gas in this boiler or in blast furnace gas-fired boilers using coke oven gas, and the coke oven gas would be flared. The use of natural gas to replace coke oven gas in this situation would be to the detriment of the environment and our energy policies.

The constraint on available capital is an additional impediment to the installation of emission control equipment because increased natural gas consumption does not require a capital investment. Before a company will invest $8.6 million in annualized control costs for a single boiler, it will need to justify a return on the capital investment far greater than $8.6 million per year in displaced natural gas. Moreover, there is no expectation that expenditures of this magnitude will be sufficient to meet the proposed Gas 2 subcategory emission limits.

Response: See the preamble for discussion of achievability of emission limits and how we modified the gas 1 subcategory to be more inclusive of other fuel types.

Commenter Name: Deb Hastings
Commenter Affiliation: Texas Oil and Gas Association
Document Control Number: EPA-HQ-OAR-2002-0058-2857.1
Comment Excerpt Number: 6

Comment: For refinery process heaters and boilers, the best performers are those where, for safety reasons, excess air levels are set somewhat above the excess air level that provides optimized energy efficiency. Typical tuning guidelines suggest an upper carbon monoxide (CO) level of 400 ppmv.

Response: See the preamble for discussion on CO limits.

Commenter Name: Ron Lindsey
Commenter Affiliation: Packaging Corporation of America
Document Control Number: EPA-HQ-OAR-2002-0058-3158
Comment Excerpt Number: 6

Comment: The proposal also creates huge hurdles for biomass boilers, with standards that are so low that they can’t even be reliably measured! These standards will result in reduced usage rates for biomass and require the use of fossil fuels in its place. It makes no sense at all to discourage the use of clean biomass fuels in the name of environmental improvement!

Response: The emission limits are revised for the final rule, see the preamble for discussion. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source.

Commenter Name: Arthur Blazer
Commenter Affiliation: Council of Western State Foresters
Document Control Number: EPA-HQ-OAR-2002-0058-2832.1
Comment Excerpt Number: 7

Comment: These rules surpass the emission regulations for European boilers and will require additional investments in emissions controls and fuel testing. This may discourage additional use of woody biomass energy by the forest products sector which increases their costs and reduces their competitiveness in international markets. Such impacts will result in economic impacts throughout the value chain related to the forest products industry.

Response: The emission limits are revised for the final rule, see the preamble for discussion. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass use.

Commenter Name: Paul Lyskava
Commenter Affiliation: Pennsylvania Forest Products Association
Document Control Number: EPA-HQ-OAR-2002-0058-2906.1
Comment Excerpt Number: 7

Comment: At a time when all government agencies should be focused on job creation and economic recovery, EPA's currently proposed regulation will have the opposite effect, further depressing business conditions, resulting in more business closings and job losses. The negative economic impacts will not be limited to those companies that fall under the proposed Boiler MACT, but also the wood and biomass residual suppliers that would be devastated by the downsizing or closing of these facilities.

Response: The emission limits and compliance options are revised for the final rule, see the preamble for discussion. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source.

Commenter Name: Tom Midyett
Commenter Affiliation: Tennessee Paper Council
Document Control Number: EPA-HQ-OAR-2002-0058-2691.1
Comment Excerpt Number: 8

Comment: The EPA proposed means of developing emission limits is so overly stringent, that the proposed Boiler MACT rule will drive some Tennessee paper mills to eliminate the use of a site-generated secondary biomass material as a fuel. In the case of one specific Tennessee mill, this will result in land filling approximately 16000 tons of mill-produced material annually. The rule may also necessitate the use of more natural gas as a fuel instead of recycled and native biomass (wood material) as a fuel. Such fuel switching will result in significant additional energy costs to the mills and will result in a loss of business to recyclers/biomass fuel providers who sell their products to the mills instead of land-filling them. The unintended consequence of replacing biomass with coal or gas is directly contrary to national energy and climate policy, which encourages the use of more renewable biomass fuel.

Response: The emission limits are revised for the final rule, see the preamble for discussion. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source.

Commenter Name: Steven W. Koehn
Commenter Affiliation: National Association of State Foresters
Document Control Number: EPA-HQ-OAR-2002-0058-2860.1
Comment Excerpt Number: 8

Comment: The proposed limits could require facilities to adopt costly new control equipment which would encourage the use of other non-renewable fuel sources. Emission limits for CO should not be overly stringent so as to discourage the conversion of coal-fired facilities to woody biomass feedstocks or the construction of new wood-based bioenergy facilities.

Response: The emission limits are revised for the final rule, see the preamble for discussion. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source.

Commenter Name: Robert R. Perry
Commenter Affiliation: FirstEnergy Generation Corp
Document Control Number: EPA-HQ-OAR-2002-0058-2772.1
Comment Excerpt Number: 8

Comment: EPA has proposed biomass limits so stringent as to choke this burgeoning industry before it even has an opportunity to develop. . As a matter of public policy, EPA should encourage the combustion of biomass as a substitute for fossil fuels. The combustion of biomass will become increasingly important to utilities as renewable energy standards are adopted by more states or in federal legislation. The combustion of biomass is sustainable with the beneficial effect of conserving natural resources. Unfortunately, the stringent MACT emission limits EPA has proposed for ICI Boilers burning biomass will greatly inhibit the combustion of biomass in the future.

Response: The emission limits are revised for the final rule, see the preamble for discussion. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source.

Commenter Name: Alicia Oman
Commenter Affiliation: National Association of Manufacturers
Document Control Number: EPA-HQ-OAR-2002-0058-2845.1
Comment Excerpt Number: 9

Comment: Biomass is a “clean” fuel in many of the same respects as the Gas 1 fuels. Biomass-fired boilers produce no net GHG emissions, which makes the combustion of biomass an important tool in managing and reducing the Nation’s carbon footprint. Similarly, biomass is an abundant, renewable domestically-produced fuel that can help reduce reliance on foreign sources of fossil fuel and, thus, improve the Nation’s energy security. Prescribing stringent HAP emissions limitations on biomass boilers will create a significant barrier to the continued use and expansion of biomass fuels and incentivize the use of less desirable fossil fuel alternatives.

Response: The emission limits are revised for the final rule, see the preamble for discussion. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source.

Commenter Name: Scott Manley
Commenter Affiliation: Wisconsin Manufacturers and Commerce
Document Control Number: EPA-HQ-OAR-2002-0058-2933.1
Comment Excerpt Number: 9

Comment: EPA’s focus on individual HAPs has resulted in a failure to recognize the critical interplay between emissions controls and emissions of other pollutants. For example, we are concerned that the controls necessary to meet the stringent emissions limitations for CO will result in increased energy usage, with the concomitant increase in emissions of NOx and other pollutants. Further, EPA failed to account for this interrelationship in its economic analysis.

Response: See the preamble for discussion on CO limits and interactions of control devices.

Commenter Name: David P. Tenny
Commenter Affiliation: National Alliance of Forest Owners
Document Control Number: EPA-HQ-OAR-2002-0058-2750.1
Comment Excerpt Number: 9

Comment: The combined effect of these arbitrary and unnecessary controls would substantially increase the cost of using biomass as a fuel source. As such, the proposed rule would negate the several government programs providing incentives to use biomass and to develop technologies reliant on biomass. With devalued incentives and increased costs, the nation would risk losing biomass as an integral part of renewable energy policy. The effect of the proposed rule would ultimately land at the foot of the forest landowner as biomass markets fail to grow or even disappear as heat and power facilities turn to other fuel sources. Most forest landowners calculate a return on their investment on a variety of markets for forest products. The elimination or dramatic reduction of a significant market such as biomass could affect the attractiveness of forestland ownership to the degree that owners look to use of the land for purposes other than forests in order to obtain an economic return.

Response: The emission limits are revised for the final rule, see the preamble for discussion. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source.

Commenter Name: Ted Sturdevant
Commenter Affiliation: Washington Department of Ecology
Document Control Number: EPA-HQ-OAR-2002-0058-2987.1
Comment Excerpt Number: 9

Comment: As EPA responds to comments, it should carefully reassess its cost benefit analysis to make sure it fully captures the consequences of the rule, whether intended or not, prior to the rule's finalization.

Response: EPA thanks the commenter for their input.

Commenter Name: Edward E. Quick
Commenter Affiliation: Celanese International Corp
Document Control Number: EPA-HQ-OAR-2002-0058-2840.1
Comment Excerpt Number: 11

Comment: There are unintended consequences if petrochemical process gases are not defined as Gas 1 streams. For example, if these streams are considered Gas 2 streams, companies will likely route these process gases to plant flares, other control devices, and/or atmosphere which will result in increased emissions and increased fuel usage.

Response: See the preamble for discussion of achievability of emission limits and how we modified the gas 1 subcategory to be more inclusive of other fuel types.

Commenter Name: Tracy Smith
Commenter Affiliation: Coastal Forest Products

Document Control Number: EPA-HQ-OAR-2002-0058-2872.1
Comment Excerpt Number: 13

Comment: The rules as proposed create a disincentive to the combustion of biomass and an incentive to burn natural gas.

The wood products industry uses a higher percentage of renewable energy than any other industry. The bark, sawdust, and other byproducts generated in the manufacturing process typically provide enough fuel to fire the boilers and meet the steam demands of the facility. The combustion of these biomass fuels is greenhouse-gas-neutral, and if these materials are not burned for fuel they will be hauled to a landfill where they will anaerobically decompose to methane gas which has 21 times the greenhouse gas impact of CO_2. Substituting a traditional fuel such as natural gas for this use will increase operating costs by as much as 30%, and if the entire wood products industry changed to natural gas, it would consume a significant percentage of the total U.S. natural gas production.

Response: The emission limits are revised for the final rule, see the preamble for discussion. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source.

Commenter Name: Douglas J. Van Pelt
Commenter Affiliation: ExxonMobil
Document Control Number: EPA-HQ-OAR-2002-0058-2968.1
Comment Excerpt Number: 14

Comment: During start-up, shutdown, and malfunction (SSM) periods, boilers and process heaters operate at off-design conditions with low firing rates and high excess air levels. At these low loads, mixing energy of the fuel and air in the combustion process is much lower. CO will increase during this operation. To further exacerbate this, in multi-burner boiler installations the industry code on combustion safety (NFPA - National Fire Protection Association) does not allow air flow reduction below 25% of design (this is purposely done to avoid explosive fuel-rich scenarios). Therefore high-excess air operation (and CO) during these periods is unavoidable. In addition, good operating practices require that equipment be gradually warmed up to operating temperature in order to prevent thermal damage in mechanical components. Equipment vendors require this gradual warm-up for equipment warranty. This proposed rule will limit the life of units due to a need to increase start-up rates creating increased stresses. Also, attempting to meet 1 ppm CO during SSM periods would discourage proper start-up and shutdown of equipment as operators would quickly ramp-up/down boilers to minimize off-design operation. This is important because the majority of combustion safety incidents, both near-misses and explosions, occur during SSM periods.

Response: EPA has revised the CO limits for the final rule, see the preamble for discussion. Also see the preamble for discussion on SSM.

Commenter Name: Douglas J. Van Pelt
Commenter Affiliation: ExxonMobil
Document Control Number: EPA-HQ-OAR-2002-0058-2968.1
Comment Excerpt Number: 15

Comment: Reducing CO to extremely low levels will require increased excess air levels which reduce efficiency, increasing the amount of fuel that must be fired and therefore increasing the total mass of other pollutants (i.e. HAPs, CO_2, NOx, SO_x, PM, etc.). Efforts to maximize boiler efficiency, and reduce NOx emissions, have also been accomplished by reducing excess air levels until the point where CO emissions begin to increase. Operation at excess air levels which result in CO emissions in the 100-400 ppm range provides the most efficient balance between stack heat loss and loss of potential energy from incomplete CO oxidation. (see submittal for Figure 9, showing HAPs at this CO range (100-400).

Response: See the preamble for discussion on CO limits.

Commenter Name: Roy W. Wood
Commenter Affiliation: Eastman Kodak Company
Document Control Number: EPA-HQ-OAR-2002-0058-2917.1
Comment Excerpt Number: 15

Comment: The optimum operating condition for energy efficiency will require facilities to perform at levels that are not optimum for emissions of other pollutants. Tuning of boilers is important and routinely conducted, but it is done to minimize emissions of traditional combustion pollutants such as NOx and CO, not just to optimize energy efficiency. Maximum energy efficiency occurs at a lower oxygen concentration than minimum air emissions. If facilities were required to maximize boiler efficiency, emissions of these pollutants will increase.

Response: See the preamble for discussion on tune-ups.

Commenter Name: Bill Wemhoff
Commenter Affiliation: National Rural Electric Cooperative Association
Document Control Number: EPA-HQ-OAR-2002-0058-2835.1
Comment Excerpt Number: 18

Comment: As a matter of public policy, EPA should encourage the combustion of biomass as substitute fuel for coal or oil. The combustion of biomass will become increasingly important to utilities as renewable energy standards are adopted by more states and are possibly applied to all states as a result of federal mandates. The combustion of biomass has the beneficial effect of conserving natural resources. Unfortunately, the stringent MACT limits EPA has proposed for IBs burning biomass will greatly inhibit the combustion of biomass in the future.

Response: The emission limits are revised for the final rule, see the preamble for discussion. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source.

Commenter Name: Jerry Osheka
Commenter Affiliation: PPG Industries
Document Control Number: EPA-HQ-OAR-2002-0058-2938.1
Comment Excerpt Number: 20

Comment: PPG believes that it is likely for many boilers that the optimum point for energy efficiency will require facilities to perform at levels that are not optimum for emissions of other pollutants. Tuning of boilers is important and routinely conducted at major facilities, but it is often done to minimize emissions of traditional combustion pollutants such as NOx and CO, which occurs at a higher oxygen level than maximum energy efficiency. These pollutants are nearly always held in check by each other. The most energy efficient operation often times does not result in the lowest levels of either NOx or CO emissions. If facilities were required to maximize boiler efficiency emissions of certain of these pollutants will increase. EPA has failed to note such issues or consider them in the proposal.

Response: See the preamble for discussion on tune-ups.

Commenter Name: Paul N. Cicio
Commenter Affiliation: Industrial Energy Consumers of America
Document Control Number: EPA-HQ-OAR-2002-0058-2752.1
Comment Excerpt Number: 25

Comment: IECA believes that it is likely for many boilers that the optimum point for energy efficiency will require facilities to perform at levels that are not optimum for emissions of other pollutants. Tuning of boilers is important and routinely conducted at major facilities, but it is often done to optimize emissions of traditional combustion pollutants such as NOx and CO, which have opposite responses to oxygen levels in the combustion zone. The most energy efficient operation typically involves minimizing excess air in the furnace, which reduces NOx formation but results in increased CO emissions. Similarly, to minimize emissions of CO would require adding excess air, with adverse impacts on both NOx formation and overall efficiency. If facilities were required to maximize boiler efficiency, emissions of certain of these pollutants will increase. EPA has failed to note such issues or consider them in the proposal.

Response: See the preamble for discussion on tune-ups.

Commenter Name: David O'Keefe
Commenter Affiliation: USEC, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-3122
Comment Excerpt Number: 29

Comment: Fly ash disposal. The proposed regulation will create fly ash that is not suitable for beneficial reuse. EPA regulations in 40 CFR §63.1344(g) and §63.1350(o) generally prohibit use of fly ash when sorbents are used for mercury control. This appears to be at odds with the EPA position taken "that the beneficial use of CCRs (and, in particular, specific beneficial uses of CCRs, such as using fly ash as a substitute for Portland cement in the production of concrete) provide significant environmental benefits, including the reduction of GHG emissions" (75 FR 35160).
EPA should consider the negative environmental impact caused by the proposal in setting the mercury standard. The mercury standard should not be so stringent as to require sorbent use for control. The mercury standard should be set to allow conventional pollution control devices (baghouses, ESPs) to achieve the standard while still allowing beneficial reuse of fly ash in an environmentally positive way. The cost benefit analysis should include the additional cost of fly ash disposal under the proposed mercury standard, which may change from a revenue producer to an operating cost. The cost and social impact of additional greenhouse gases, etc., should also be included.

Response: See the preamble for discussion on revised limits and control devices.

Commenter Name: Richard L. Killion
Commenter Affiliation: Babcock and Wilcox Power Generation Group
Document Control Number: EPA-HQ-OAR-2002-0058-2722.1
Comment Excerpt Number: 31

Comment: Implementation of the industrial MACT would not necessarily decrease fuel usage. One of the means to control CO is to increase excess air to the unit which would decrease unit efficiency and increase fuel usage. The allowance for decreased fuel usage should be removed or reduced from the engineering cost analysis.

Response: See the preamble for discussion on CO limits and their impact on emissions.

Commenter Name: David M. Kiser
Commenter Affiliation: International Paper Company
Document Control Number: EPA-HQ-OAR-2002-0058-2777.1
Comment Excerpt Number: 32

Comment: As a nation, we have stated goals of energy conservation, limiting our greenhouse gas emission footprint, recycling and decreasing our dependence on foreign sources for energy. In addition, the global economy is just starting to come out from under the shadow of the worst economic recession in decades. The economy is fragile and job preservation and growth are key for the economy to recuperate and grow. All of these are laudable goals and objectives to have as a nation. However, this suite of proposed rules, including but not limited to the Boiler MACT rule, are inconsistent with these objectives.

The Boiler MACT rule requires "coal boilers", defined as any unit that burns more than 10 % coal on a heat input basis, to meet a CO limit that is not achievable in practice with combustion controls for boilers co-firing biomass. As a result the Boiler MACT rule provides strong disincentive to continuing to burn biomass. In fact to do so International Paper (and EPA) believe such boilers would need to be retrofit with combustion catalysts which cost on the order of $15 million each and which require addition of natural gas burners to reheat cleaned and cooled exhaust gases to nearly 500 to 750 degrees F in order to burn trace residual organic HAP that may be present. Reheating fuel gas alone will cost on the order of $5 million per year per unit for natural gas and as a result will contribute to increases in NOx and CO_2 emissions to such a degree that a typical pulp mill combination fuel boiler will need to undergo new source review permitting for GHG in order to install controls to meet the Boiler MACT rule. This technology review would be likely to discount the value of the combustion catalyst as it will significantly degrade the energy efficiency of the boiler. Then one rule will be requiring a control that another rule would suggest should not be built. This result would of course be untenable. The increased NOx and CO_2 also represent an increased adverse environmental impact or detriment associated with the Boiler MACT rule. (EPA apparently did not understand that combustion catalysts require roughly 500 degree gas temperatures to combust CO and higher temperatures on the order of 750°F to control organics HAPs.)

Response: See the preamble for new subcategory definitions and discussion of CO limits.

Commenter Name: Traylor Champion
Commenter Affiliation: Georgia-Pacific LLC
Document Control Number: EPA-HQ-OAR-2002-0058-2745.1
Comment Excerpt Number: 32

Comment: EPA has assumed would be available to meet HCl limits may in fact be unavailable due to constraints on wastewater discharges.

part 429.11(c) so that the discharge prohibition in 40 CFR part 429 would not apply to wastewaters associated with air pollution control devices (APCD) operation and maintenance when used to comply with the final Boiler MACT rule. § 429.11 General definitions should be amended to read as follows (changes highlighted in Bold/Underline):
"(c) The term "process wastewater" specifically excludes non-contact cooling water, material storage yard runoff (either raw material or processed wood storage), boiler blow down, and wastewater from washout of thermal oxidizers or catalytic oxidizers, wastewater from biofilters,

wastewater from air pollution control devices on boilers and process heaters or wastewater from wet electrostatic precipitators used upstream of thermal oxidizers or catalytic oxidizers installed by facilities covered by subparts B, C, D or M to comply with the national emissions standards for hazardous air pollutants (NESHAP) for plywood and composite wood products (PCWP) facilities (40 CFR part 63, subpart DDDD); for Industrial, Commercial, and Institutional Boilers and Process Heaters at major source facilities (40 CFR 63 Subpart DDDDD) and
for Industrial, Commercial, and Institutional Boilers at area sources (40 CFR 63 Subpart JJJJJJ). For the dry process hardboard, veneer, finishing, particleboard, and sawmills and plaining mills subcategories, fire control water is excluded from the definition.

Background

The effluent guidelines for the Timber Products Processing Point Source Category in 40 CFR part 429 subparts B (Veneer subcategory), C (Plywood subcategory),
D (Dry Process Hardboard subcategory), and M (Particleboard Manufacturing subcategory), prohibit the discharge of process wastewater pollutants. We believe that the effluent limitations for these wastewaters should be developed by permit writers on a case-by-case basis based upon best professional judgment. This issue was adequately addressed and resolved for the PCWP MACT Rule where the EPA excluded the definition of process wastewaters in 40 CFR 29.11(c) for the wastewaters associated with APCD used by PCWP facilities covered by subparts B, C, D, and M to comply with 40 CFR 63.22: wastewater from washout of thermal oxidizers and catalytic oxidizers, wastewater from biofilters, and wastewater from WESP used upstream of thermal oxidizers or catalytic oxidizers. Refer to 69 FR 45964, for more details. EPA specifically excluded
wastewater generated by three processes and associated APCDs necessary to meet the PCWP NESHAP from coverage by the existing effluent limitations
guidelines. These three processes and associated process wastewaters are: (1) washing out RTOs or RCOs; (2) WESPs used upstream of RTOs/RCOs to protect them from plugging with particulate; and (3) biofilters. The resulting amended definition of process wastewater is shown below:

§ 429.11 General definitions.

* * * * *

(c) The term “process wastewater” specifically excludes non-contact cooling water, material storage yard runoff (either raw material or processed wood storage), boiler blow down, and wastewater from washout of thermal oxidizers or catalytic oxidizers, wastewater from biofilters, or wastewater from wet electrostatic precipitators used upstream of thermal oxidizers or catalytic oxidizers installed by facilities covered by subparts B, C, D or M to comply with the national emissions standards for hazardous air pollutants (NESHAP) for plywood and composite wood products (PCWP) facilities (40 CFR part 63, subpart DDDD). For the dry process hardboard, veneer, finishing, particleboard, and sawmills and plaining mills subcategories, fire control water is excluded from the definition.

We believe the same data used for the PCWP MACT rule can be used for the Boiler MACT in that the issue and argument are essentially the same. It will be extremely difficult for structural and engineered wood panels manufacturing facilities to meet the proposed Boiler MACT rule without allowing the discharge of wastewater from APCD used to meet Boiler MACT. Control of PM and HCl to achieve the proposed Boiler MACT emission limits, will require the use of a wet device. The use of a wet electrostatic precipitator may require the discharge of at least 10 gallons per minute of blow down or 14,400 gallons per day.

As stated in the preamble to the PCWP MACT rule, until effluent limitations guidelines and standards for pollutants in process wastewaters from structural and engineered wood panels manufacturing facilities are promulgated, Best Practicable Technology (BPT) and BAT effluent limitations should be established on a case-bycase basis under 40 CFR 125.3. This way, individual facilities seeking a discharge permit will have the opportunity, on a case-by-case basis, to characterize and obtain discharge allowances for their wastewaters from APCD installed to comply with the final Boiler MACT standards. The permit writer would be expected to determine, based upon best professional judgment (BPJ), the appropriate effluent limitations for these APCD wastewaters. (See 40 CFR 125.3.) The permit writer can take into account facility-specific information on wastewater volumes and pollutants, available wastewater control and treatment technologies, costs and effluent reduction benefits, receiving water quality, and any applicable State water quality standards. EPA should consider amending the existing effluent limitations guidelines and standards for the Timber Processing Industry to cover process wastewaters. Such an effort would involve gathering and analyzing the information and data necessary to establish revised categorical effluent limitations affecting subparts B, C, D, and M of 40 CFR part 429 for these APCD wastewaters generated in complying with the final Boiler MACT standards. GP recognizes that this change ultimately will require communication with the appropriate staff in the Office of Water.
GP urges EPA to adopt changes to the Effluent Guidelines for Timber Products Processing. Specifically, we request that EPA amend the definition of process wastewaters at 40 CFR part 429.11(c) so that the discharge prohibition in 40 CFR part 429 would not apply to wastewaters associated with air pollution control devices (APCD) operation and maintenance when installed to comply
with the final Boiler MACT rule. § 429.11 General definitions should be amended to read as follows (changes in bold):
"(c) The term "process wastewater" specifically excludes non-contact cooling water, material storage yard runoff (either raw material or processed wood storage), boiler blow down, and wastewater from washout of thermal oxidizers or catalytic oxidizers, wastewater from biofilters, wastewater from air pollution control devices on boilers and process heaters or wastewater from wet electrostatic precipitators used upstream of thermal oxidizers or catalytic oxidizers installed by facilities covered by subparts B, C, D or M to comply with the national emissions standards for hazardous air pollutants (NESHAP) for plywood and composite wood products (PCWP) facilities (40 CFR part 63, subpart DDDD); for Industrial, Commercial, and Institutional Boilers and Process Heaters at major source facilities (40 CFR 63 Subpart DDDDD); for Industrial, Commercial, and Institutional Boilers at area sources (40 CFR 63 Subpart JJJJJJ). For the dry process hardboard, veneer, finishing, particleboard, and sawmills and planing mills subcategories, fire control water is excluded from the definition.

Response: See the response to comment EPA-HQ-OAR-2002-0058-2797.1, excerpt 26.

Commenter Name: Chris Korleski
Commenter Affiliation: Ohio EPA
Document Control Number: EPA-HQ-OAR-2002-0058-2818.1
Comment Excerpt Number: 33

Comment: EPA's MACT rule appears to be at odds with SDA's Biomass Crop Assistance Program and other federal initiatives designed to rapidly expand a competitive, sustainable and reliable biomass energy market. The MACT rule, as currently drafted, has the potential to stop progress made under these programs instead of promoting renewable fuels.

Response: The emission limits are revised for the final rule, see the preamble for discussion. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source.

Commenter Name: Christopher S. Colman
Commenter Affiliation: Hovensa LLC
Document Control Number: EPA-HQ-OAR-2002-0058-2863.1
Comment Excerpt Number: 35

Comment: As was noted with respect to small remote incinerators, island/remote facilities have very similar issues relating to water and to solid waste. In the case of remote Alaska facilities, it is the inability to use wet gas scrubbing because of cold weather. For island facilities such as HOVENSA, water is extremely scarce and must be produced by desalination. The cost of this water and the emissions from producing it are significant. Wastewater (generated from a wet scrubber for example) would have to be treated at the refinery as no municipal treatment plant in St. Croix could accept it. Likewise, HOVENSA is not located near industrial solid waste facilities and must typically ship these wastes thousands of miles at high cost to receiving facilities elsewhere. Thus, control dusts from baghouses or ESP systems would have to be shipped elsewhere.

Response: See the preamble for discussion on the new non-continental states and territories subcategory.

Commenter Name: Brad James
Commenter Affiliation: Trinity Consultants
Document Control Number: EPA-HQ-OAR-2002-0058-2853.1
Comment Excerpt Number: 35

Comment: EPA has clearly established a disincentive for installation of new biomass boilers and other environmentally beneficial projects, which conflicts with the Obama administration's and Congress' intention to move towards greater renewable energy usage and reduction in fossil fuel usage.

Response: The emission limits are revised for the final rule, see the preamble for discussion. See the response to EPA-HQ-OAR-2002-0058-2860.1, excerpt 6 regarding biomass as a renewable energy source.

Commenter Name: Brad James
Commenter Affiliation: Trinity Consultants
Document Control Number: EPA-HQ-OAR-2002-0058-2853.1
Comment Excerpt Number: 36

Comment: By establishing new source limits that are not realistically achievable by a new emission unit, EPA is promoting the reliance on older, less efficient energy/steam generating sources as well as units with emission profiles that are generally worse than new units. U.S. Sugar and all other facilities that may wish to retire older units to install new boilers would be prohibited from doing so under the unachievable proposed Boiler MACT. For example, Boiler No. 8 at the Clewiston facility was designed to be the most efficient bagasse boiler when it began commercial operation in 2005. The unit has state-of-the-art control technology to meet the Best Available Control Technology (BACT) requirements of the Prevention of Significant Deterioration program. While it is acknowledged that new source MACT is different than BACT, the best controlled units for PM and CO should also be the “best controlled similar source”.

Therefore, even if U.S. Sugar wanted to install new boilers with the capabilities of the best boiler currently operating, the unachievable proposed standards of the Boiler MACT would preclude these environmentally beneficial projects. This is obviously not the Congressional intent when establishing the requirements of CAA Section 112.

Response: See the preamble for discussion of achievability of emission limits and how we modified the gas 1 subcategory to be more inclusive of other fuel types.

Commenter Name: Sarah E. Amick
Commenter Affiliation: Rubber Manufacturers Association
Document Control Number: EPA-HQ-OAR-2002-0058-2941.1
Comment Excerpt Number: 37

Comment: EPA provides no justification for restricting averaging to a given subcategory nor is it rational to impose such a restriction. Emissions averaging generally allows a facility to avoid otherwise cost-prohibitive compliance options by over-controlling some other emission unit in a more cost-effective combination. It also has corresponding environmental benefits, by creating an incentive to burn more natural gas or renewable fuels such as biomass as a strategy to average out emissions from a coal-fired unit. If the Boiler Rule does not allow averaging across the different fuel categories, EPA removes that incentive for sources to turn to cleaner-burning fuels to achieve averaging benefits.

Response: EPA has determined it is not appropriate to allow emission averaging across subcategories. EPA does not do this in other rules with mixed streams (e.g., SOCMI) and the commenter does not provide sufficient justification for swaying from this precedent.

Commenter Name: Douglas J. Van Pelt
Commenter Affiliation: ExxonMobil
Document Control Number: EPA-HQ-OAR-2002-0058-2968.1
Comment Excerpt Number: 39

Comment: EPA's proposed emission limits, particularly for Gas 2 sources and considered for Gas 1 sources, by themselves result in non-optimum operation of boilers/process heaters by increasing fuel consumption and other pollutants (e.g. NOx). EPA should modify the proposed rule to encourage efficient boiler/process heater operation in the base case with the appropriate boiler tune-up requirements instead of numeric emission limits that result in inefficient operation. EPA's analysis did not factor in higher costs due to increased fuel consumption and emission increases associated with non-optimum boiler/process heater operation.

Response: See the preamble for discussion of achievability of emission limits and how we modified the gas 1 subcategory to be more inclusive of other fuel types.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 61

Comment: The limits being proposed in this rule will mandate combinations of emission controls that have adverse effects on each other. In short, the presence of one control technology may prevent a second control technology from operating at optimum performance.

A primary control for Hg emissions involves the injection of activated carbon into the flue gas. The mercury is oxidized on the active sites on the carbon particles. The oxidized form of mercury can then either be recovered by particulate control equipment or by a scrubber (since oxidized mercury is soluble). The oxidation reactions only occur at temperatures below about 350ºF. The effectiveness of the activated carbon for oxidizing mercury is dependent upon the amount of time that the carbon has to attract the mercury to one of its active sites.

The use of activated carbon injection for mercury control is negatively affected by the presence of sulfur trioxide (SO_3). SO_3 occupies the active sites on the carbon, taking away those sites from the mercury. Even a few parts per million of SO_3 can have a significant negative impact on the mercury removal to be achieved by activated carbon injection. For example, due in part to inherently higher SO_3 emissions, Stoker fired boilers see reduced Hg reduction compared to pulverized coal (PC) boilers. Other control devices, such as CO oxidation catalyst or SCR NOx reduction catalyst, will convert an additional percentage of the SO2 to SO3, resulting in poor mercury removal. EPA can avoid this problem by establishing standards on the basis of a source approach that properly accounts for the impact of multiple controls and the interactions between fuel sulfur, chloride, mercury, and alkali metals, as suggested earlier in these comments.

Response: See the preamble for discussion of achievability of emission limits and how we modified the gas 1 subcategory to be more inclusive of other fuel types.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 116

Comment: Large integrated chemical plant sites strive to be as energy efficient as possible. One way to promote energy efficiency is to capture off-gas from petrochemical and chemical plant off-gas streams and re-use these streams as fuel in a variety of combustion sources. Plant sites are designed to use many types of "Gas 2" streams as a fuel in order to have energy efficient operations. If Gas 2 fuels are subjected to stringent emission limits instead of work practice requirements, the rule likely will force facilities to dispose of process off-gases in other types of combustion sources including flares, which results in more natural gas being used, inefficient operations, and an increase in greenhouse gas emissions.

Response: See the preamble for discussion of achievability of emission limits and how we modified the gas 1 subcategory to be more inclusive of other fuel types.

Health Benefits

Commenter Name: Norbord Industries
Commenter Name: Norbord Industries
Commenter Affiliation: Norbord Industries
Document Control Number: EPA-HQ-OAR-2002-0058-0854.1
Comment Excerpt Number: 9

Comment: EPA has seemed to focus on criteria pollutants in many of its justifications for establishing certain limits. Shouldn't those limits be established in accordance to an equivalent reduction in HAPs? For instance, did EPA set PM standards based on PM or metals? The same can be said for CO, as it is generally well known that burners must be operated at temperatures well above those needed to destroy organic HAPs.

Response: EPA has based its PM and CO limits on the best performing units in each subcategory for each of these pollutants. EPA has determined that PM is an appropriate surrogate for non-Hg metals and that CO is an appropriate surrogate for non-dioxin organic HAP. By reducing emissions of PM and CO, emissions of these other HAP will decrease. See response to comments related to the appropriateness of surrogates under codes 6A-6Z.

Commenter Name: Los Angeles Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1778
Comment Excerpt Number: 76

Comment: We object to the U.S. EPA using only health risk assessments as its only measure of public health impacts. HRAs are not based on any public health baseline from a scientifically conducted health survey of impacted environmental justice communities. HRAs do not identify all public health impacts by illness category; do not identify how many people are afflicted, and cannot tell you if cancer is increasing or decreasing.

We request the U.S. EPA include a health impact assessment to provide information not provided in a health impact assessment. You quote in there -- as one of my final things -- that you would be avoiding 110 to 300 premature deaths in 2003. Obviously, the staff did not look at our figures in the harbor. We average that number of deaths every single day in the L.A. harbor community. So before quoting a number you need to look at the actual data, which you're going to get from the Los Angeles County Department of Health and the California Department of Health. And those will provide you reliable numbers. And with regard to the health assessments you will be describing, will you have some further description as to what those assessments should be considering?

MR. MARQUEZ: Yes. There is a provided consulting firm, Health Impact Partners, that conducts these. And U.C.L.A. and U.C. Berkeley both have institutes or departments within the universities that also specialize in health assessments.

So that you do know, U.S. EPA Region 9 last year attended a class and sent about six to seven members. As well as L.A. County Department of Health sent about four to five staff members, in addition to about 15 of us E.J. organizations and attended a class

here in Los Angeles. Actually, it was about two years
ago. And in all of the public comments that have been
made regarding that course and movement, they have
recommended a health impact assessment to perform in
addition to an HRA.

Response: EPA agrees that it is informative to estimate how many fewer people would experience air pollution-related health effects as a result of this regulation. The regulatory impact analysis conducted as part of the rule includes a health impact assessment, which quantifies a variety of health effects avoided by the rule, including mortality, hospital visits, asthma attacks, school loss days, among others at the national level. It is important to note that air pollution is only one of many contributing causes of mortality and morbidity.

Commenter Name: Los Angeles Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1778
Comment Excerpt Number: 85

Comment: Your inventory air pollution inventory is only an estimate. If your
inventory is on there -- is underestimating. The public
health risk assessment is significantly underestimated.

Response: We have adjusted the inventory since the proposal to reflect comments received on new facilities or facilities missing from the existing inventory. The revised costs and emission reduction analysis reflects this revised inventory.

Commenter Name: Arlington Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1779
Comment Excerpt Number: 66

Comment: For those of us that like to exercise outside, the reduction of these pollutants is not just an academic or legalistic discussion. I bicycle to work on a daily basis, from Maryland, across the District of Columbia, and into Virginia. On one hand, that exercise is substantially improve my physical fitness; but on the other hand, lungful of lead, cadmium, dioxide, and God knows what else, certainly doesn’t do much for my well being.

As I said at the outset, I’m not an expert -– medical expert, a chemical engineer, but I am an accountant by training and profession. The EPA, to their credit, has done an in-depth cost-benefit analysis of these proposed regulations. Without going into great detail, it’s pretty clear that the benefits to be achieved on an overall or on a large scale –- on a macro basis far outweigh the cost of implementation.

Obviously there's going to be local dislocations as we've heard one of the previous speakers point out; but I think if we look at the large picture, this is not something that,, in fact, is a cost but a long-term benefit.

We just finished watching the political drama of enacting major health care reform legislation. If nothing else, we've come away from that conversation with a clear, clear understanding that the long-term cost of health care in this country is measured in the hundreds of billions of dollars. And anything that we can do to reduce that cost will have a resounding and positive economic impact. These rules are going to do that.

We've waited way too long for these rules to be proposed by EPA. This is not something radical. This is not dangerous. This is not economically destructive. These rules are just plain common sense. It's common sense that we don't want our kids -– my kids – breathing mercury. It's common sense that formaldehyde is not good for anyone's lungs, and it's just common sense that the economic cost of an asthma attack triggered by minimally regulated particulates is simply unacceptable these days.

Response: EPA agrees that exposure to particulates and toxic air pollutants can cause severe health effects and reducing exposure to these pollutants is associated with substantial public health benefits.

Commenter Name: Arlington Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1779
Comment Excerpt Number: 68

Comment: These boilers and incinerators produce particulate matter -– tiny bits of solids and aerosols formed by the sulfur dioxide and nitrogen oxide emissions. Particulate matter is the most dangerous of the widespread air pollutants. Particulate matter triggers asthma attacks, heart attacks, and strokes, among other damage, but most critically, particulate matter kills. Breathing find particles increases the risk that children with asthma and older adults with chronic obstructive pulmonary disease or cardiovascular disease will end up in the emergency room or the hospital.

These units also spread mercury and lead, hazardous metals that can harm children's brains, hurting their IQ and limiting their ability to learn and to remember what they have learned. Cleaning up these boilers and incinerators will save lives. EPA estimates that between 2,000 and 5,000 lives will be saved every year because of the changes put in place by these requirements beginning in 2013.

But that's only part of the benefits. Having less pollution to breathe should benefit –- should prevent over 3,000 non-fatal heart attacks, avoid over 35,000 cases of worsened asthma, and eliminate nearly 3,400 hospital and emergency room visits each year –- each year.

Response: EPA agrees that exposure to particulates and toxic air pollutants can cause severe health effects and reducing exposure to these pollutants is associated with substantial public health benefits.

Commenter Name: Arlington Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1779
Comment Excerpt Number: 103

Comment: So let me just focus on something that EPA itself concluded. The major source boiler rule will save 4,800 lives every year -– 4,800 lives that would be lost prematurely if this rule were weakened or as industry seeks, there were a health-based exemption thrown in. And that's just the tip of the iceberg because when EPA counted the number of lives that would be saved, it only looked at the emission reductions of fine particulate matter.

It didn't look at the 7 tons of mercury that would be reduced or the literally thousands of tons of lead and arsenic and chromium that we reduced, or the dioxins, or the formaldehyde, or the benzene. Yet all of these things have very serious health effects. These metals can cause cancer. So can benzene and formaldehyde and dioxins. Mercury can cause birth defects and developmental damage in children. So, if the real health effects were taken into account, we'd be looking at a lot more than 5,000 lives saved. We don't know how many it is because EPA doesn't quantify or monetize it.

But let me get back to the monetization also because those 4,800 lives are worth billions more than the cost to industry will be. In fact, by EPA's calculations even with just 4,800 lives the ratio is about 5 to 1 or 10 to 1 in terms of benefits to costs. It would be far more overwhelming if the full benefits were calculated.

Response: EPA agrees that exposure to particulates and toxic air pollutants can cause severe health effects and reducing exposure to these pollutants is associated with substantial public health benefits.

Commenter Name: Arlington Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1779
Comment Excerpt Number: 122

Comment: The new rules will protect students and residents who live near and downwind from those coal –- excuse me -– coal-burning boilers. Emissions of toxic air pollution such as mercury, arsenic, cadmium, and acid gases, would be significantly reduced. These pollutants are extremely dangerous, and EPA's actions will help remove thousands of pounds of toxics from the air, including 15,000 pounds of mercury and tens of thousands of tons of acidic gases that cause breathing problems, particularly in vulnerable individuals like children and the elderly. About 36,000 asthma attacks could be prevented each year and result in approximately $18 to $44 billion in health savings annually, according to the EPA's analysis.

Mercury is an extremely dangerous neurotoxin that can impact a child's ability to walk, talk, read, write, and learn. The mercury problem in the United States is so pervasive that one in six women today have mercury levels in their blood high enough to put her baby at risk, according to the EPA. High mercury levels have also been linked to an increased risk of heart disease in men.

We need drastic reductions in toxic pollution and greenhouse gas pollution, and these boilers are a major source of this pollution, even if not individually, then cumulatively. There are nearly 14,000 major source boilers alone around the country. Even the smaller types of boilers burning coal and waste present a grave threat to human health and the environment. Toxins like mercury and selenium are harmful even in small doses, and many of these facilities are located in very highly populated areas.

Response: EPA agrees that exposure to particulates and toxic air pollutants can cause severe health effects and reducing exposure to these pollutants is associated with substantial public health benefits.

Commenter Name: Arlington Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1779
Comment Excerpt Number: 130

Comment: This isn't about over-regulation or jobs. This really is about saving taxpayers and the U.S. Government millions –- actually billions of dollars a year in terms of missed school days, missed work days, emergency room visits, respiratory arrest. There are several –- I think it's 4,800 unnecessary deaths are going to be avoided by instituting or finalizing the MACT rule. And that's certainly been something that we're encouraged to see in the environmental and also the public health community.

Response: EPA agrees that exposure to particulates and toxic air pollutants can cause severe health effects and reducing exposure to these pollutants is associated with substantial public health benefits.

Commenter Name: Arlington Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1779
Comment Excerpt Number: 133

Comment: The technology is available off the shelf for all of those size boilers; and yes, it will cost a little bit of money to do it, but it essentially is going to -– hopefully, even in doing a cost-benefit analysis you look at our toxic rules and the CBAs actually show that there are tremendous values to having protective rules.

And so I think it's really about creating a rule that's genuinely protective and at the very least having an inventory of all the facilities across this country of what they're burning, in what quantities they're burning.

Response: EPA agrees that exposure to fine particulates and toxic air pollutants is associated with severe health effects and reducing exposure to these pollutants is associated with substantial public health benefits.

Commenter Name: Arlington Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1779
Comment Excerpt Number: 135

Comment: I wanted to come as a private citizen because, I mean, I live in D.C. When you look around, we are impacted by petrochemical industries and chemical industries not because they're right here in our back yard but because they're basically upwind and because we're downwind, we're failing at our air toxics tests.

There are reasons why basically our lungs are being poisoned and they're not because of emissions that are happening right here in our back yards. And a lot of it are coming from boilers and incinerators that aren't being regulated with off-the-shelf technology. And for us, it's just really important to see communities protected.

I'm a person who's of childbearing age. I am probably going to be having kids in the next five years. I have no idea what pollutants are going into my lungs, what those pollutants are going to have on my reproductive system, what they are going to have on my potential children down the line. And as I get older, it just gets more distressing that the EPA basically has the authority to move forward with promulgating protective rules, yet we're seeing things like the definition of solid waste that genuinely are protective of people.

Response: EPA agrees that exposure to fine particulates and toxic air pollutants is associated with severe health effects and reducing exposure to these pollutants is associated with substantial public health benefits.

Commenter Name: Arlington Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters

Document Control Number: EPA-HQ-OAR-2002-0058-1779
Comment Excerpt Number: 138

Comment: We know that powerful industry lobbies are lining up to oppose these rules. They want the loopholes and exemptions. We want the rules -– they want the rules weakened and delayed.

These rules will prevent about 4,800 unnecessary deaths each -– every year and will save billions of dollars in costs -– medical costs, time costs, costs to communities in terms of lost time and lost -– and lost ability to externalities to be able to work, live, and play in a safe environment.

The benefits overwhelm the costs by a ratio of between 5 and 10 to 1. And that's only the tip of the iceberg. It only reflects the health benefits by reducing major source boilers' emissions of fine particulate matter. It doesn't count the benefits of eliminating more than seven tons of mercury emissions every year that cause birth defects in babies and developmental damage in young children, or thousands of tons of lead, cadmium, and other metals that are known as suspected carcinogens, or the dioxins and other organic pollutants that cause cancer.

Response: EPA agrees that exposure to particulates and toxic air pollutants can cause severe health effects and reducing exposure to these pollutants is associated with substantial public health benefits.

Commenter Name: Margaret Sheehan
Commenter Affiliation: Energy Justice Network
Document Control Number: EPA-HQ-OAR-2002-0058-1884.1
Comment Excerpt Number: 4

Comment: Methylmercury poisoning can also affect adults, and symptoms may include impairment of peripheral vision; disturbances in sensations ("pins and needles" feelings, usually in the hands, feet, and around the mouth); lack of coordination of movements; impairment of speech, hearing, walking; and muscle weakness.
Effects of methylmercury exposure on wildlife can include mortality (death), reduced fertility, slower growth and development, and abnormal behavior that can affect survival.

Response: EPA agrees that exposure to methylmercury can have substantial health effects.

Commenter Name: Margaret Sheehan
Commenter Affiliation: Energy Justice Network
Document Control Number: EPA-HQ-OAR-2002-0058-1884.1
Comment Excerpt Number: 8

Comment: Wood products release dioxin when they are incinerated in the presence of chlorine [See reference 15 provided by commenter]. Lignin is the organic substance that makes up woody tissue. Burning chlorine in the presence of certain precursors to dioxin, including lignin, releases dioxin into the environment [See reference 16 provided by commenter]. In incinerators, the amount of dioxin formed by burning seems to depend largely on the chlorine content in the waste that is burned [See reference 17 provided by commenter]. The paper and pulp industry use chlorine to bleach paper. Id. When the paper is incinerated, the chlorine and lignin create dioxin [See reference 18 provided by commenter]. Similarly, burning lumber treated with pentachlorophenol, which the lumber industry uses to preserve wood, creates dioxin [See reference 19 provided by commenter]. Burning wood releases dioxins [See reference 20 provided by commenter]. This fact demonstrates that the burning of wood in incinerators, even when the wood is not processed by the paper and pulp industries, can result in the creation of dioxin.

Dioxin is highly toxic and can cause reproductive and developmental problems, damage the immune system, interfere with hormones and also cause cancer [See reference 21 provided by commenter]. Once dioxin has entered the body, it persists a long time because of its chemical stability and its ability to be absorbed by fat tissue, where it is stored in the body. The Department of Human Health and Services determined that it is reasonable to expect dioxin to cause cancer, among many other adverse health effects [See reference 22 provided by commenter].
Dioxin contamination has far-reaching consequences. A study by the North American Commission for Environmental Cooperation showed that dioxin from United States sources, including the combustion of wood, contaminate Inuit traditional foods such as caribou and fish, and lead to high concentrations of dioxins in Inuit mothers' milk [See reference 23 provided by commenter].

Response: EPA agrees that exposure to particulates and toxic air pollutants can cause severe health effects and reducing exposure to these pollutants is associated with substantial public health benefits.

Commenter Name: Richard T. Metcalf
Commenter Affiliation: Louisiana Mid-Continent Oil and Gas Association
Document Control Number: EPA-HQ-OAR-2002-0058-2699.1
Comment Excerpt Number: 13

Comment: EPA overestimated health benefits.
* EPA argues that the large costs of this rule are justified by the co-benefits of PM reductions. Ironically, add-on controls for gas units would actually cause PM to increase. Moreover, there is still much uncertainty in the science community over EPA's extrapolation of mortality risks to low ambient levels, but the costs are much more certain.

Response: In many instances, it is not possible to quantify and monetize all of the benefits associated with a regulatory action due to data, resource, and methodological limitations. For this rule, we were only able to monetize the benefits associated with reducing exposure to PM2.5 as a result of reducing direct PM2.5 emission and PM2.5 precursor emissions such as SO2. 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.

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. Co-benefits that occur as a result of a regulatory action are appropriate to include in the RIA, and it is appropriate to compare the total monetized benefits with the costs.

The weight of scientific evidence strongly supports modeling PM-related mortality and morbidity by using concentration-response functions that do not incorporate an assumed threshold. In 2009, the final Integrated Science Assessment for Particulate Matter indicated that "[o]verall, the studies evaluated further support the use of a no-threshold log-linear model…" (U.S. EPA, 2009). In 2010, the Health Effects Subcommittee of the Science Advisory Board "fully supports EPA's decision to use a no-threshold model to estimate mortality reductions. This decision is supported by the data, which are quite consistent in showing effects down to the lowest measured levels. Analyses of cohorts using data from more recent years, during which time PM concentrations have fallen, continue to report strong associations with mortality. Therefore, there is no evidence to support a truncation of the CRF" (EPA-SAB-COUNCIL- 10-001). Our approach to estimating PM-related health impacts is consistent with the key findings in these reports. In addition, our approach is consistent with the on-going PM NAAQS review.

In conjunction with the commenter's concern and consistent with recent scientific advice, we have replaced the previous threshold sensitivity analysis with a new "lowest measured level" (LML) assessment. While an LML assessment provides some insight into the level of uncertainty in the estimated PM mortality benefits, EPA does not view the LML as a threshold and continues to quantify the PM-related mortality impacts using the full range of modeled air quality concentrations.

In the regulatory impact analysis, we account for the emission disbenefits to the extent feasible.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 226

Comment: 4. It is a significant and questionable shift for the EPA to attempt to justify regulations under HAP reduction authority on a basis other than HAP reductions. The CAA provides different authorities and different procedures for addressing criteria pollutants and HAPs. Congress established separate procedures to allow optimization of the requirements addressing these very different types of pollutants and to minimize the disruption to the economy by applying inappropriate approaches to each. Basing HAP rules on their estimated criteria pollutant impacts circumvents Congress‘s intent and the procedures for addressing criteria pollutants established by the CAA. The benefits associated with criteria pollutant reductions have already been claimed under the NAAQS rulemakings and procedures and it is inappropriate to claim the same benefits again.

Recommendations: Reevaluate this proposal based only on its HAP impacts.

Response: In many instances, it is not possible to quantify and monetize all of the benefits associated with a regulatory action due to data, resource, and methodological limitations. For this rule, we were only able to monetize the benefits associated with reducing exposure to PM2.5 as a result of reducing direct PM2.5 emission and PM2.5 precursor emissions such as SO2. 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.

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. Co-benefits that occur as a result of a regulatory action are appropriate to include in the RIA, and it is appropriate to compare the total monetized benefits with the costs.

Commenter Name: Julie E. Goodman, B. Rey de Castro, Margaret C. Pollock
Commenter Affiliation: Gradient Corporation
Document Control Number: EPA-HQ-OAR-2002-0058-2715.2
Comment Excerpt Number: 9

Comment: The potential magnitude of the net social benefits associated with a standard set with the UPL at the 95th (or 90th) percentile is notable. Although the benefits from reducing mercury emissions by 7.5 tons/year have not been monetized by US EPA in its Regulatory Impact Analysis (RIA), the RIA indicates that the annualized net benefits from reducing PM2.5 and its precursors would yield a net benefit on the order of $14 billion to $38 billion (2008$, 3% discount rate, in 2013), compared to a total social cost of only $2.9 billion. If the net benefits of reducing mercury are at all proportional to those for PM2.5 and its precursors, a further 38.4% reduction in mercury emissions (assuming implementation of a 95th percentile UPL rather than a 99th percentile UPL) would potentially yield billions of dollars in additional net social benefit. Such social benefits would include not only the monetized economic and social effects US EPA considered in its RIA, but also real-world improvements in population health, ecosystem sustainability, and visibility (US EPA, 2010a).

Response: EPA agrees that the monetized net social benefits are notable and that we were unable to quantify the benefits associated with mercury reductions. Although the mercury benefits would be substantial, it is unlikely that mercury benefits (if monetized) are proportional to the monetized PM benefits due to the size of the exposed population and the severity of the health effects.

Commenter Name: Henry T. Graham
Commenter Affiliation: Louisiana Chemical Association
Document Control Number: EPA-HQ-OAR-2002-0058-2731.1
Comment Excerpt Number: 13

Comment: EPA argues that the large costs of this rule are justified by the co-benefits of PM reductions. Ironically, add-on controls for gas units would actually cause PM to increase. Moreover, there is still much uncertainty in the science community over EPA's extrapolation of mortality risks to low ambient levels, but the costs are much more certain.

Response: 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. In many instances, it is not possible to quantify and monetize all of the benefits associated with a regulatory action.

After reviewing the scientific literature, EPA has determined that the no-threshold model is the most appropriate model for assessing the mortality benefits associated with reducing PM2.5 exposure. In the final rule, we have incorporated a new "lowest measured level" assessment to highlight the fraction of benefits that occur at low concentrations of PM2.5. This analysis shows that most of the PM-related benefits would accrue to populations exposed to higher levels of PM.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 223

Comment: The lack of health benefits from for the requirements proposed for gas-fired equipment have been hidden by only discussing health benefits on a total proposal basis. There is negligible health benefit associated with the proposal for gas-fired boilers and process heaters because there are negligible HAP and criteria pollutant reductions associated with those units. In particular, most of the claimed benefits for this proposal come from EPA's estimated PM2.5 reductions. Yet, PM2.5 emissions from gas-fired units are negligible in the base, so any reductions will be even more negligible. In fact, where emission controls are imposed on gas-fired equipment, PM2.5 emissions are likely to increase because of the PM created by the controls.

Recommendation: EPA should evaluate the proposal health benefits on a subcategory basis and demonstrate that there are net pollutant reductions and therefore potential health benefits for any subcategory it regulates.

Response: In the regulatory impact analysis for the proposal, we provide pie charts (Figures 6-4 and 6-5) to illustrate the fraction of monetized PM2.5 benefits by subcategory, including gas boilers.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 224

Comment: EPA did not appropriately consider health impacts resulting from increased NOx, CO_2 and HAP emissions from meeting proposed extremely low CO limits on units where add-on controls are not installed. Nor have the health impacts been evaluated of increased dioxin/furan emissions due to lowering the stack temperatures of boilers and process heaters to accommodate the add-on controls necessary to attempt to comply with this proposal. Nor has the health impact of increased particulate emissions from gas-fired units as the result of installing activated carbon controls or oxidation catalyst been considered.

Recommendation: Incorporate the health disbenefits of this proposal into the record and rulemaking analyses.

Response: In the regulatory impact analysis, we account for the emission disbenefits to the extent feasible.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 225

Comment: The majority of the claimed health benefits of this proposal are derived from the co-benefits of reducing PM2.5 and PM2.5 precursors. These reductions are anticipated to result from the installation of controls to limit HAP emissions. To calculate the economic benefits of reducing PM2.5, EPA used a risk assessment approach that extrapolates health impacts to the lowest levels of PM2.5 observed in air quality modeling. This non-threshold based risk assessment approach results in a marked increase in the estimated economic benefits of reducing each ton of PM2.5 emissions versus historical methodologies. As the American Chemistry Council discusses at length in their comments on the proposed NESHAP from the Portland Cement Manufacturing Industry, [Footnote: EPA-HQ-OAR-2002-0051-2849.2, posted 9/8/09]

EPA has not provided scientific justification for its proposed approach of extrapolating PM mortality risks to the lowest modeled ambient levels. An examination of the expert group advice cited by EPA in support of this approach reveals mostly the opposite, i.e., preference for the use of a threshold or apparent threshold for PM risk assessment. A critical review of the published literature also fails to provide support for EPA‘s new method for PM risk assessment. Many of the published studies cite evidence for nonlinearity and thresholds. Therefore, we do not believe that EPA‘s new approach to extrapolate mortality risks attributed to exposure to ambient PM linearly to the lowest modeled levels is or can be scientifically supported.

In addition, the benefit per ton approach used by EPA in this RIA does not consider changes in population exposure or baseline health rates and therefore does not conform to EPA guidelines for performing RIAs. EPA has not considered the full range of concentration response functions for chronic mortality which if used would significantly lower the range of benefits estimates. EPA has inappropriately used opinions of selected experts as a substitute for data in their economic analysis. Finally, EPA has used an inaccurate metric to derive estimates of the economic value of reduced chronic mortality.

As a result, the alleged health benefits attributed to reductions in exposure to PM2.5 and their estimated economic impact claimed in this rulemaking fail because they are built on a faulty foundation.

Recommendation: Re-evaluate the claimed health benefits for the estimated PM2.5 reductions attributed to this proposal using the traditional and scientifically validated threshold or apparent threshold approach.

Response: The weight of scientific evidence strongly supports modeling PM-related mortality and morbidity by using concentration-response functions that do not incorporate an assumed threshold. In 2009, the final Integrated Science Assessment for Particulate Matter indicated that "[o]verall, the studies evaluated further support the use of a no-threshold log-linear model…" (U.S. EPA, 2009). In 2010, the Health Effects Subcommittee of the Science Advisory Board "fully supports EPA's decision to use a no-threshold model to estimate mortality reductions. This decision is supported by the data, which are quite consistent in showing effects down to the lowest measured levels. Analyses of cohorts using data from more recent years, during which time PM concentrations have fallen, continue to report strong associations with mortality. Therefore, there is no evidence to support a truncation of the CRF" (EPA-SAB-COUNCIL- 10-001). Our approach to estimating PM-related health impacts is consistent with the key findings in these reports. In addition, our approach is consistent with the on-going PM NAAQS review.

In conjunction with the commenter's concern and consistent with recent scientific advice, we have replaced the previous threshold sensitivity analysis with a new "lowest measured level" (LML) assessment. While an LML assessment provides some insight into the level of uncertainty in the estimated PM mortality benefits, EPA does not view the LML as a threshold and continues to quantify the PM-related mortality impacts using the full range of modeled air quality concentrations.

Commenter Name: Bobby B. Howell
Commenter Affiliation: Mississippi House of Representatives
Document Control Number: EPA-HQ-OAR-2002-0058-3193
Comment Excerpt Number: 5

Comment: I do not believe this very stringent rule is necessary and certainly will have a negative effect on the industries affected. I understand that many of the environmental concerns have no proven threat to human health.

Response: Exposure to fine particulates and toxic air pollutants is associated with severe health effects and reducing exposure to these pollutants is associated with substantial public health benefits.

Commenter Name: Steve Smith
Commenter Affiliation: LyondellBasell Industries
Document Control Number: EPA-HQ-OAR-2002-0058-3118.1
Comment Excerpt Number: 6

Comment: Develop cost and benefit analyses on a source subcategory basis. EPA has evaluated this proposal on a total source category basis, primarily by taking credit for presumably large PM reductions from certain solid fuel categories. This approach hides the fact that there are essentially no HAP, PM or other emission reductions associated with the gas subcategories to justify the proposal or even the imposition of a technology standard.

Response: In the regulatory impact analysis (RIA), we provide pie charts to illustrate the fraction of benefits by subcategory, including the fraction associated with gas boilers.

Commenter Name: Anna Garcia
Commenter Affiliation: Ozone Transport Commission
Document Control Number: EPA-HQ-OAR-2002-0058-2725.1
Comment Excerpt Number: 1

Comment: OTC advises EPA in developing the final rule that the Agency needs to be sensitive to the impact of the boiler MACT on other pollutants, specifically nitrogen oxides (NOx) and sulfur dioxides (SO2). The proposed boiler MACT appropriately focuses on hazardous air pollutants (HAPs), and not on these two criteria pollutants. However, Industrial, Commercial and Institutional (ICI) boilers emit significant amounts of NOx, which are a component of ozone and particulate pollution, and SO2, also a component of particulate pollution. These compounds reduce lung function, aggravate asthma and other respiratory illnesses, and contribute to premature death. NOx and SO2 emissions are also components of acid rain pollution, which damages forests and erodes structures. These pollutants further damage the environment through eutrophication of waterways, which contaminates water and affects plant and animal health, and reduction in visibility in parks and wilderness areas. EPA should ensure that compliance with the boiler MACT does not result in increasing emissions of NOx and SO2 into the environment.

Response: In the regulatory impact analysis, we account for the emission disbenefits to the extent feasible.

Commenter Name: Douglas J. Van Pelt
Commenter Affiliation: ExxonMobil
Document Control Number: EPA-HQ-OAR-2002-0058-2968.2
Comment Excerpt Number: 1

Comment: EPA's benefit per ton approach does not conform with it's own Guidelines for Performing RIAs

According to EPA, due to analytical limitations, they did not provide a comprehensive risk-based approach to evaluate PM2.5 related benefits. Rather, EPA used the "benefit-per-ton" approach. With this approach, EPA provides no estimate of the changes in population exposure that will result from implementation of this rule. Furthermore, the benefit-per-ton approach does not considerer local variability in population density, meteorology, baseline health incidence rates, or other local factors that will certainly influence the risk estimates. Since many of these factors are mentioned as key factors to include in the EPA Guidelines for Performing an RIA, the RIA does not conform to EPA's own guidelines for performing an RIA.

Response: For the final major source rule, EPA has provided a more comprehensive benefits analysis that includes sector-specific air quality modeling and benefits modeling. The methodology used for the proposal analysis for estimating the health benefits associated with reducing PM2.5 and precursor emissions is based on peer-reviewed publications (see Fann, Fulcher, and Hubbell, 2009). Even though national average benefit-per-ton estimates are inherently more uncertain than sector-specific modeling, EPA has high confidence in the magnitude of total monetized benefits at the national level, but the benefits for specific locations may vary.

Commenter Name: Douglas J. Van Pelt
Commenter Affiliation: ExxonMobil
Document Control Number: EPA-HQ-OAR-2002-0058-2968.2
Comment Excerpt Number: 2

Comment: Since chronic mortality accounts for over 90 percent of the benefits of PM2.5 benefits reductions, the concentration response function (CRF) used for this health endpoint is critical. As mentioned above, EPA's upper and lower range of benefits are derived using mortality estimates from Pope et al. and Laden et al. EPA provides no clear rationale for using these single point values from two chronic air pollution studies. Other CRFs are available from these same studies as well as those from many other peer reviewed studies from the U.S. and other regions (e.g. Krewski et al. 2000; Enstrom, 2005; Beelen et al. 2008). Since the majority of the CRFs not considered by EPA indicate a lower range of mortality risks, and some even report no statistically significant association between exposure to fine PM and chronic mortality, the approach used by EPA results in an upper bias in risks and benefits.

There are many serious scientific concerns with the study by Laden et al. (2006) which EPA uses to support their upper bound mortality estimates. These concerns, which should disqualify this study for use in risk assessment, are discussed in detail in the American Chemistry Council comments on EPA's new methodology to estimate the benefits of PM reductions (ACC, 2009). For example, the results are not based on actual PM2.5 exposures since PM2.5 measurements were discontinued long ago in the six cities examined. The results are based on single pollutant models; confounding by other pollutants was not examined. In five of the six cities, the risk coefficients are not statistically significant.

In the RIA, EPA states that the CRFs they use from Pope et al. and Laden et al. were adjusted using multi-pollutant models (pg 6-3). This is incorrect. The CRF EPA used for chronic mortality from Pope et al and Laden et al were not adjusted for any other pollutant. In the case of Pope et al. 2002, EPA is using a version of the ACS study that did not evaluate confounding by other pollutants. In the 2000 reanalysis of ACS study reported by Krewski et al., results for PM2.5 in a two pollutant model with SO2 are available. However, EPA did not use these results. Krewski et al. reported that inclusion of SO2 dramatically decreased the chronic mortality attributed to PM2.5 to less than 2 percent per 10 ug/m3 and the results were no longer statistically significant. In the case of Laden et al., as mentioned above, multi-pollutant models were not used. Thus, for both studies, EPA is assigning the entire impact of reductions in air pollution to a single pollutant, PM2.5. Since EPA claims all of these other pollutants potentially also cause mortality and morbidity, EPA is double and triple counting the benefits of air pollution reduction.

Response: The choice of studies used to estimate the relationship between PM2.5 and premature mortality has been extensively reviewed and supported by EPA's Science Advisory Board, and the rationale for using both the Pope et al. (2002) and Laden et al. (2006) studies is explained in the regulatory impact analysis.

Commenter Name: Ronald Saff
Commenter Affiliation: Citizen
Document Control Number: EPA-HQ-OAR-2002-0058-3205
Comment Excerpt Number: 2

Comment: Biomass plants release tons of particle pollution, this is no secret, it says so in their applications.
According to the American Heart Association, there is no safe threshold for particle pollution, in other words, there is no safe level or number. The AHA states that the National Ambient Air

Quality Standards (NAAQS) standards are not stringent enough to protect our health. There is a linear relationship between the amount of air pollution and the amount of heart attacks and death, not only from heart disease but from ALL CAUSES. In other words, the higher the level of particle pollution, the higher the death rate and the only safe level is zero.

In a Nov 16 2009 letter from Scott Keays of the American Lung Association to Sen. Kerry here are some of the specific wordings: "Burning wood, like burning any other substance, releases toxic chemicals and particles which can negatively affect both the environment and respiratory health". "Biomass and diesel emissions are particularly harmful." "The concerns about generating electricity through biomass become even more troubling when you consider how wasteful and inefficient this source of power is." “Given the technology and the natural resources available to us, we do not believe that anyone should be forced to choose between electric power and their health".

In a Feb 4 2010 statement, the Physicians for Social Responsibility stated "If the proposed biomass power plants are built in the Pioneer Valley, the resulting excess air pollution would exacerbate an already unacceptable public health burden."

The Massachusetts Medical Society and the Florida Medical Association, worried about the health impacts of biomass plants, have also come out with statements against them.
In recognition of the numerous and serious adverse health consequences that can result from human exposure to the components of emissions of biomass burning, the North Carolina Academy of Family Physicians (NCAFP) has issued a letter of concern regarding the development of biomass burning plants in the State of North Carolina on April 19, 2010.

In short, the hazardous health impacts including death, disease and cancer is well known and acknowledged by the medical community; physician groups and medical associations representing tens of thousands of doctors across the U.S. have weighed in against the deadly impacts of biomass plants. The media will likely link any further decisions to approve biomass plants with those specific government officials that gave the approval, this could be a "career - ender".

Response: EPA agrees that exposure to fine particulates and toxic air pollutants is associated with severe health effects and reducing exposure to these pollutants is associated with substantial public health benefits.

Commenter Name: Douglas J. Van Pelt
Commenter Affiliation: ExxonMobil
Document Control Number: EPA-HQ-OAR-2002-0058-2968.2
Comment Excerpt Number: 3

Comment: EPA indiscriminately applies to CRF for PM2.5 chronic mortality to all forms of PM including soluble sulfate PM which is a common form of PM predicted to be reduced by this rule. EPA ignores scientific evidence that suggests that sulfate aerosols exhibit a lower toxic potential than other forms of PM (Schlesinger et al. 2003). First, soluble forms of PM such as nitrate, sulfate, and ammonium PM exhibit much lower toxicity potential than carbonaceous PM (soot) with high metal content. Further, soluble PM distributes in the upper respiratory tract and is less likely to produce systemic toxic effects (e.g. chronic mortality) than non-water soluble fine PM that distribute in the lower respiratory tract. In particular, there is an extensive toxicology database that indicates that sulfate PM presents low toxicity potential. EPA's "onesize-fits-all" approach results in over-estimating the risks of emissions from this rule, since a large portion of PM EPA predicts from boiler emissions is water soluble secondary sulfate PM.

Response: In the regulatory impact analysis, EPA clearly notes that the benefits models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because there is no clear scientific evidence that would support the development of differential effects estimates by particle type.

Commenter Name: Bruce Coffee
Commenter Affiliation: Hurst Boiler and Welding Co
Document Control Number: EPA-HQ-OAR-2002-0058-2705.1
Comment Excerpt Number: 3

Comment: The justification for the action is admirable, but short-sighted, as the detrimental effect of the loss of work and the decrease in quality of life caused by this action will more than offset the few lives and discomforts the proponents enumerate as justification AND ACTUALLY COST LIVES! One would have to believe, based on the justification, that most of these solid-fuel-burning sources are all placed in urban settings, in reality, most are in rural, low-population areas. It has been widely discussed, researched and proven that UNEMPLOYMENT causes far more deaths, drug use, domestic violence, smoking, dependency, etc than this list. So, it will have the opposite effect than that they hope to achieve. According to the CDC reports that the deaths per 100,000 rose from an all-time low of 760 in 2007 to 838 in 2009 due to the economic downturn, essentially unemployment. That is an increase of 234,000. This occurred even as the emissions from boilers were decreased by a large percentage due also to the economic downturn. I believe this correlationessentially negates the justification and exposes the projection of mortality improvements as a myopic grasp that ends up being a rounding error. This is certain.

Response: Based on the conclusions of EPA's Integrated Science Assessment on Particulate Matter (U.S. EPA, 2009), long term exposure to fine particles has a causal link to premature mortality, even at low ambient levels. In addition, exposure to fine particles is associated with cardiovascular and respiratory health effects. The methodology for estimating the health benefits associated with reducing PM2.5 and precursor emissions is based on peer-reviewed publications (see Fann, Fulcher, and Hubbell, 2009).

Commenter Name: Douglas J. Van Pelt

Commenter Affiliation: ExxonMobil
Document Control Number: EPA-HQ-OAR-2002-0058-2968.2
Comment Excerpt Number: 4

Comment: EPA has inappropriately applied a linear no threshold approach to assess all forms of PM

EPA uses a linear no threshold approach to assess mortality. This approach results in a significant (3-10 fold) increase in estimated mortality versus a more logical approach that assumes the existence of an effects threshold. While the threshold approach has become the default that EPA uses for all risk assessments of ambient PM, the linear no threshold approach for sulfate PM is not supported by the actual underlying epidemiology data.

In a re-analysis of the original ACS-Pope study, the authors examined the concentration response relationship for sulfate PM and concluded that there is a threshold for chronic mortality near the concentration of 12 µg/m3.(Abrahamowicz et al. 2003, Krewski et al 2000). Since in most locations of the U.S., sulfate PM levels are already below this level, further reductions are expected to produce no change in chronic mortality.

Response: The weight of scientific evidence strongly supports modeling PM-related mortality and morbidity by using concentration-response functions that do not incorporate an assumed threshold. In 2009, the final Integrated Science Assessment for Particulate Matter indicated that "[o]verall, the studies evaluated further support the use of a no-threshold log-linear model…" (U.S. EPA, 2009). In 2010, the Health Effects Subcommittee of the Science Advisory Board "fully supports EPA's decision to use a no-threshold model to estimate mortality reductions. This decision is supported by the data, which are quite consistent in showing effects down to the lowest measured levels. Analyses of cohorts using data from more recent years, during which time PM concentrations have fallen, continue to report strong associations with mortality. Therefore, there is no evidence to support a truncation of the CRF" (EPA-SAB-COUNCIL- 10-001). Our approach to estimating PM-related health impacts is consistent with the key findings in these reports. In addition, our approach is consistent with the on-going PM NAAQS review.

In conjunction with the commenter's concern and consistent with recent scientific advice, we have replaced the previous threshold sensitivity analysis with a new "lowest measured level" (LML) assessment. While an LML assessment provides some insight into the level of uncertainty in the estimated PM mortality benefits, EPA does not view the LML as a threshold and continues to quantify the PM-related mortality impacts using the full range of modeled air quality concentrations.

Commenter Name: Douglas J. Van Pelt
Commenter Affiliation: ExxonMobil
Document Control Number: EPA-HQ-OAR-2002-0058-2968.2
Comment Excerpt Number: 6

Comment: EPA used an inaccurate metric to value chronic mortality

Presenting estimates of premature or additional deaths related to air pollution is the default approach used by EPA. However, as noted by Rabl (2006), estimating the number of premature deaths due to air pollution is the most accurate metric.

First, it makes little sense to add the number of deaths independently due to different contributing causes, such as air pollution, smoking or lack of exercise because doing so could result in a number far in excess of total mortality. When individual air pollutants are considered without adequately adjusting for other pollutants, this may lead to double counting of deaths in the analysis.

Second, the number of deaths fails to take into account the magnitude of the loss of life expectancy per death, which is very different between, for example, air pollution deaths, typically occurring in older people, and traffic accidents, typically occurring in younger people.

Third, in contrast to the primary causes of deaths for example heart disease and cancer, with ecologic air pollution studies, it is not possible to accurately estimate the total number of premature deaths attributable to air pollution. The reason is that ecologic air pollution studies provide population-based "years of life lost", but not individual years of life lost per death. Therefore, it is not known if a few individuals lose a number of years of life, or if many individuals lose only a few months.

For these reasons, Rabl et al. (2003, 2006) and others have suggested expressing air pollution mortality in terms of "Loss of Life Expectancy" (LLE) changes or value of a life year (VOLY). This framework automatically takes into account the constraint that everybody dies exactly once, regardless of their exposure or lack thereof, to air pollution. The VOLY approach was recognized by the European Union (EU) as providing a more accurate and meaningful metric to quantify potential chronic effects of air pollution, and this approach was used to evaluate various policy options for reducing PM air pollution under the EU Clean Air for Europe program.

Response: EPA continues work to update its guidance on valuing mortality risk reductions, which is currently referred to as the value of a statistical life (VSL). The Agency determined that a single, peer-reviewed estimate applied consistently best reflects the advice it has received from the Science Advisory Board while the Agency continues its efforts to update its guidance on this issue. This VSL is $6.3 million (2000$), which was calculated as the mean VSL across 26 studies. The Agency is committed to using scientifically sound, appropriately reviewed evidence in valuing mortality risk reductions and has made significant progress in responding to the Science Advisory Board's specific recommendations.

Commenter Name: Douglas J. Van Pelt
Commenter Affiliation: ExxonMobil
Document Control Number: EPA-HQ-OAR-2002-0058-2968.2

Comment Excerpt Number: 7

Comment: To develop their figures of societal benefits of $17-41 and $15-37 billion per year, EPA used a figure of $8.9 million for the value of a statistical life (VSL). This figure was derived from U.S.-based studies of willingness to pay and contingent valuation and the results therefore reflect socioeconomic preferences expressed by the U.S. population. There are vast differences in results of such studies based on socioeconomic differences. Furthermore, the willingness to pay/contingent valuation studies used to support the above figure were not specific to the assessment of air pollution. Rather, most of these studies were based on accidental deaths, with most deaths occurring at younger ages (30-40 years) than expected to results from air pollution.

Recently, a study to evaluate the monetary valuation of mortality and morbidity risk from air pollution, conducted under the EU Sixth Framework Programme, has been published (NEEDs, 2007). The objective of the study was to provide more reliable and credible estimates of the VOLY lost by air pollution mortality. For the EU 16 and New Member Countries, figures of 40,000 Euro and 25,000 Euro, respectively, were recommended. These values were based on use of mean figures. Using median values, which minimizes the impact of extreme values, figures of 19,000 and 15,000 Euro, respectively, were reported. These figures highlight the extreme nature of the $6.3 million VSL value used by EPA. We encourage EPA to conduct a similar study for the U.S. and replace the currently used VSL with a more accurate VOLY metric derived from willingness to pay for studies specific for air pollution. The exaggerated VSL figure EPA currently uses significantly contributes to a dramatic over-estimate of the economic benefits of reducing air pollution. Even the most conservative estimates of the life years lost from chronic exposure to air pollution are on the order of a few years.

Similarly, the World Health Organization (WHO) uses the quality adjusted life year (QALY) approach, rather than the VSL approach, to assess the impact of air pollution on mortality. The NEEDs study recommends QALY values on the order of 50,000 Euro. Again, using this approach, much lower figures of economic benefits of reduced boiler emissions of PM would be realized.

Response: EPA continues work to update its guidance on valuing mortality risk reductions, which is currently referred to as the value of a statistical life (VSL). The Agency determined that a single, peer-reviewed estimate applied consistently best reflects the advice it has received from the Science Advisory Board while the Agency continues its efforts to update its guidance on this issue. This VSL is $6.3 million (2000$), which was calculated as the mean VSL across 26 studies. The Agency is committed to using scientifically sound, appropriately reviewed evidence in valuing mortality risk reductions and has made significant progress in responding to the Science Advisory Board's specific recommendations.

Commenter Name: Dan F. Hunter
Commenter Affiliation: ConocoPhillips Company
Document Control Number: EPA-HQ-OAR-2002-0058-2867.1
Comment Excerpt Number: 7

Comment: EPA argues that the large costs of this rule are justified by the co-benefits of PM reductions. Ironically, suggested add-on controls for gas-fired sources for PM would actually cause PM to increase. In fact, PM emissions from gas-fired units are so inherently low as to require established measurement techniques to be modified by significantly extending routine testing periods in an attempt to recover enough material to quantify emissions.

Response: In the regulatory impact analysis, we account for the emission disbenefits to the extent feasible.

Commenter Name: Douglas J. Van Pelt
Commenter Affiliation: ExxonMobil
Document Control Number: EPA-HQ-OAR-2002-0058-2968.2
Comment Excerpt Number: 8

Comment: EPA is inappropriately using reductions of PM2.5 to justify a myriad of regulations whose primary focus is not on control of PM2.5.

Table 1 of the submittal provides a partial list of the regulations and proposed regulations where EPA has included reductions in PM2.5 in the corresponding RIA. Even though most of the regulations do not focus on regulation of PM2.5 but rather other NAAQS pollutants and HAPs, the vast majority of the total economic benefits (88-91 percent) are due to reductions of PM2.5. In our view, the total monetary benefit that EPA estimates from these reductions in PM2.5, which is on the order of $300-450 billion, is not realistic.

Table 2 of the submittal provides a partial list of the health benefits that EPA has estimated due to implementation of selected regulations and reductions in PM2.5. Again, in our view, the overall total estimates are not realistic.

Response: In many instances, it is not possible to quantify and monetize all of the benefits associated with a regulatory action due to data, resource, and methodological limitations. For this rule, we were only able to monetize the benefits associated with reducing exposure to PM2.5 as a result of reducing direct PM2.5 emission and PM2.5 precursor emissions such as SO2. 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.

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. Co-benefits that occur as a result of a regulatory action are appropriate to include in the RIA, and it is appropriate to compare the total monetized benefits with the costs.

EPA anticipates PM and SO2 emission reductions as a result of this rule, and the benefits associated with these emission reductions are appropriate to include in this RIA. These emission reductions would occur regardless of an area's attainment status under the NAAQS, but these emission reductions might help those areas that are in non-attainment to reach attainment.

Commenter Name: Deb Hastings
Commenter Affiliation: Texas Oil and Gas Association
Document Control Number: EPA-HQ-OAR-2002-0058-2857.1
Comment Excerpt Number: 13

Comment: EPA argues that the large costs of this rule are justified by the co-benefits of PM reductions. Ironically, add-on controls for gas units would actually cause PM to increase. Moreover, there is still much uncertainty in the science community over EPA's extrapolation of mortality risks to low ambient levels, but the costs are much more certain.

Response: The weight of scientific evidence strongly supports modeling PM-related mortality and morbidity by using concentration-response functions that do not incorporate an assumed threshold. In 2009, the final Integrated Science Assessment for Particulate Matter indicated that "[o]verall, the studies evaluated further support the use of a no-threshold log-linear model…" (U.S. EPA, 2009). In 2010, the Health Effects Subcommittee of the Science Advisory Board "fully supports EPA's decision to use a no-threshold model to estimate mortality reductions. This decision is supported by the data, which are quite consistent in showing effects down to the lowest measured levels. Analyses of cohorts using data from more recent years, during which time PM concentrations have fallen, continue to report strong associations with mortality. Therefore, there is no evidence to support a truncation of the CRF" (EPA-SAB-COUNCIL- 10-001). Our approach to estimating PM-related health impacts is consistent with the key findings in these reports. In addition, our approach is consistent with the on-going PM NAAQS review.

In conjunction with the commenter's concern and consistent with recent scientific advice, we have replaced the previous threshold sensitivity analysis with a new "lowest measured level" (LML) assessment. While an LML assessment provides some insight into the level of uncertainty in the estimated PM mortality benefits, EPA does not view the LML as a threshold and continues to quantify the PM-related mortality impacts using the full range of modeled air quality concentrations.

In the regulatory impact analysis, we account for the emission disbenefits to the extent feasible.

Commenter Name: Barry Christensen
Commenter Affiliation: Occidental Chemical Corp
Document Control Number: EPA-HQ-OAR-2002-0058-2848.1

Comment Excerpt Number: 24

Comment: Health benefits of the rule should be based on HAP reductions. The benefits of the rule should include the monetized benefits from reductions in HAP and not be limited solely to reductions in criteria pollutant benefits such as PM2.5.

Response: In many instances, it is not possible to quantify and monetize all of the benefits associated with a regulatory action due to data, resource, and methodological limitations. For this rule, we were only able to monetize the benefits associated with reducing exposure to PM2.5 as a result of reducing direct PM2.5 emission and PM2.5 precursor emissions such as SO2. 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.

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. Co-benefits that occur as a result of a regulatory action are appropriate to include in the RIA, and it is appropriate to compare the total monetized benefits with the costs.

EPA anticipates PM and SO2 emission reductions as a result of this rule, and the benefits associated with these emission reductions are appropriate to include in this RIA. These emission reductions would occur regardless of an area's attainment status under the NAAQS, but these emission reductions might help those areas that are in non-attainment to reach attainment.

Commenter Name: Michael Hutcheson
Commenter Affiliation: Ameren Services
Document Control Number: EPA-HQ-OAR-2002-0058-2803.1
Comment Excerpt Number: 32

Comment: Ameren believes the benefits analysis conducted for the proposed rule is flawed and overestimates the changes in ambient levels of PM2.5 used to estimate the monetized benefits of the rule.
The use of the Fann et al. (2009) methodology to estimate reduction in ambient levels of PM2.5 is improper. The Fann et al. methodology has not undergone a rigorous peer review as should be required for any methodology utilized by US EPA for estimating the effects of a regulatory scheme on the health of the US population. The Fann, et al. methodology uses a flawed emission inventory (US EPA's 2001 National Emissions Inventory) and projects that inventory out to 2015. The 2001 inventory has been replaced with a newer inventory which should have been utilized. Because Fann does not include the revised inventory in the open sourced study, it is impossible to see how Fann projected emissions out to 2015. He only makes a vague statement that the projected inventory includes several federal regulatory programs such as CAIR.

Fann utilizes the CMAQ version 4.4 regional air quality model to estimate PM2.5 ambient air quality levels associated with various regulatory schemes. The CMAQ version 4.4 model has several flaws which render it's use to estimate PM2.5 levels inappropriate without a comparison to actual PM2.5 levels in modeled areas. This version of CMAQ significantly overestimates PM2.5 levels when compared to actual measured PM2.5 levels. Because CMAQ overestimates PM2.5, several updates to this model have been made to correct these known deficiencies. Despite these known problems, Fann et al. make no effort to correct for this overestimation or make any comparison to actual measured PM2.5 levels. Consequently, it can be presumed that the model as used by Fann, overestimates PM2.5 ambient air quality levels resulting from each ton of direct PM2.5 and PM2.5 precursors. This will necessarily result in an overestimation of the change in PM2.5 level resulting from the reduction of each ton of direct PM2.5 and PM2.5 precursors. Similarly, by overestimating the change in PM2.5 ambient air quality levels, the Fann et al. methodology also overestimates the benefits of the associated reductions.

US EPA should not utilize outdated versions of regional air quality models which over estimate impacts when analyzing the economic impacts associated with the proposed regulations. US EPA should revise this analysis to properly account for the deficiencies of the Fann methodology and the associated inventory and regional air quality model.

Response: For the final major source rule, EPA has provided a more comprehensive benefits analysis that includes sector-specific air quality modeling and benefits modeling. The methodology used for the proposal analysis for estimating the health benefits associated with reducing PM2.5 and precursor emissions is based on peer-reviewed publications (see Fann, Fulcher, and Hubbell, 2009). Even though national average benefit-per-ton estimates are inherently more uncertain than sector-specific modeling, EPA has high confidence in the magnitude of total monetized benefits at the national level, but the benefits for specific locations may vary.

Commenter Name: Douglas J. Van Pelt
Commenter Affiliation: ExxonMobil
Document Control Number: EPA-HQ-OAR-2002-0058-2968.1
Comment Excerpt Number: 75

Comment: The particulate matter health benefits assessment in the Regulatory Impact Analysis (RIA) was not determined correctly and should be reevaluated.

EPA attributes all of the economic benefits in the RIA to reductions in particulate matter, a criteria pollutant. EPA was unable to quantify the benefits of any HAP reductions that might be achieved by the proposed rule. It is questionable for EPA to justify a regulation focused on HAP reductions on the basis of reductions in criteria pollutants. The Clean Air Act provides different authorities and different procedures for addressing criteria pollutants and HAPs. Congress established separate regulatory programs to address these very different types of pollutants and to minimize the disruption to the economy by applying specifically designed approaches to each. Furthermore, EPA has already claimed the benefits associated with PM under the NAAQS rulemakings and procedures. By claiming these benefits again under HAP reductions, EPA is double-counting the benefits of PM reductions. This is part of a wider trend whereby EPA is inappropriately using “co-benefits” of PM reductions to justify a myriad of regulatory actions that focus on pollutants other than PM.

As described in the detailed comments included in Attachment 1, the methodology EPA used to quantify the benefits of reducing PM emissions is not scientifically sound and significantly over-estimates the benefits. The key concerns are: 1) EPA’s benefit per ton approach does not consider changes in population exposure or baseline health rates and does no conform with it’s own guidelines for performing RIAs; 2) EPA has not considered the full range of concentration response functions for chronic mortality; 3) EPA has inappropriately applied a linear no threshold approach to assess all forms of PM and extrapolated mortality far beyond the data in the underlying studies and below background levels; 4) EPA has inappropriately used opinions of selected experts as a substitute for data in an economic analysis and ; 5) EPA has used an inaccurate metric to value chronic mortality. When taken in total and when compared to background causes of disease and mortality, the overall benefits EPA is claiming from PM reductions are unrealistic.

EPA should reevaluate the particulate matter benefits claimed as described below:

Determine the health benefits of hazardous air pollutant (HAP) reductions associated with the proposed rule; this is a HAP rule, not a criteria pollutant rule.

Reevaluate the claimed health benefits using a more scientifically sound basis for the estimated particulate reductions.

Response: In many instances, it is not possible to quantify and monetize all of the benefits associated with a regulatory action due to data, resource, and methodological limitations. For this rule, we were only able to monetize the benefits associated with reducing exposure to PM2.5 as a result of reducing direct PM2.5 emission and PM2.5 precursor emissions such as SO2. 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.

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. Co-benefits that occur as a result of a regulatory action are appropriate to include in the RIA, and it is appropriate to compare the total monetized benefits with the costs.

EPA anticipates PM and SO2 emission reductions as a result of this rule, and the benefits associated with these emission reductions are appropriate to include in this RIA. These emission reductions would occur regardless of an area’s attainment status under the NAAQS, but these emission reductions might help those areas that are in non-attainment to reach attainment.

Commenter Name: Michael A. Livermore
Commenter Affiliation: Institute for Policy Integrity, New York University School of Law

Document Control Number: EPA-HQ-OAR-2002-0058-2720.1
Comment Excerpt Number: 6

Comment: More Stringent Standards Are Likely Required to Maximize Net Benefits
If more stringent standards did not increase social welfare, EPA would be justified in solely using the "MACT floor" emission standards, as determined by Section 112(d)(3). But the figures presented in the EPA's regulatory impact analysis ("RIA") indicate that this may not be the case. High ratios of benefits to costs may indicate under-regulation. Figure 1 shows a graphical depiction of the marginal costs and benefits of a hypothetical optimized regulation, where the stringency of the regulation has been set to equalize marginal costs and marginal benefits. Area A (the area underneath the marginal cost curve) represents the total social costs of the regulation. The combination of Areas A, B, and C (the total area underneath the marginal benefit curve) represents the total social benefits of the regulation. In this simple linear example, this gives a ratio of 3:1 for total benefits to total costs.

[See submittal for Figure 1. Depiction of Hypothetical Optimized Regulation]

By contrast, Figure 2 shows a graphical depiction of the marginal costs and benefits of a hypothetical scenario of under-regulation, where marginal costs have been set well below marginal benefits. Area D (the area underneath the marginal cost curve) represents the total social costs of the regulation. The combination of Areas D, E, and F (the total area underneath the marginal benefit curve) represents the total social benefits of the regulation. In this example, the ratio of total benefits to total costs is 7:1.

[See submittal for Figure 2. Depiction of Hypothetical Under-Regulation]

These twin examples show how under-regulation leads to a higher ratio of total benefits to total costs.
Table 1 shows the costs and benefits of the Major Source Proposal and Area Source Proposal at a discount rate of 7%. [Footnote: Note that choosing the higher discount rate minimizes the ratio in this case.]

[See submittal for Table 1. Total Costs and Benefits of Proposed Major and Area Source Rules at 7% Discount Rate (Millions of 2008$)]

Given the range of benefit estimates, the ratio of benefits to costs is between 5 and 13 for the Major Source Proposal and between 1.8 and 4.4 for the Area Source Proposal. As demonstrated by the simple example above, this may indicate that the agency is under-regulating in at least the Major Source Proposal. The RIA also excludes many highly significant benefits categories that the agency did not have the time or analytical ability to quantify. [Footnote: For example, the RIA concentrates on the health effects related to particulate matter reductions, and "[t]he benefits from reducing hazardous air pollutants have not been monetized in this analysis, including reducing 370,000 tons of carbon monoxide, 37,000 tons of HCl, 1,000 tons of HF, 8.3 tons of mercury, 3,400 tons of other metals, and 1,200 grams of dioxins/furans each year." RESEARCH TRIANGLE INSTITUTE, RTI PROJECT NUMBER 0209897.004.074, REGULATORY IMPACT ANALYSIS: NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR

POLLUTANTS FOR INDUSTRIAL, COMMERCIAL, AND INSTITUTIONAL BOILERS AND PROCESS HEATERS at 6-1 (Draft Report, Prepared for EPA, Apr. 2010) [hereinafter RIA].] This means that the true benefit-to-cost ratios are almost certainly higher than those indicated by the table.

While the RIA indicates that there are no additional benefits from regulating major sources with heat input capacity under 10 MMBtu/hr, [Footnote: For example, the RIA concentrates on the health effects related to particulate matter reductions, and "[t]he benefits from reducing hazardous air pollutants have not been monetized in this analysis, including reducing 370,000 tons of carbon monoxide, 37,000 tons of HCl, 1,000 tons of HF, 8.3 tons of mercury, 3,400 tons of other metals, and 1,200 grams of dioxins/furans each year." RESEARCH TRIANGLE INSTITUTE, RTI PROJECT NUMBER 0209897.004.074, REGULATORY IMPACT ANALYSIS: NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR INDUSTRIAL, COMMERCIAL, AND INSTITUTIONAL BOILERS AND PROCESS HEATERS at 6-1 (Draft Report, Prepared for EPA, Apr. 2010) [hereinafter RIA] at 6-31.] this does not show that the costs of additional emissions standards on sources with heat input capacity over 10 MMBtu/hr are higher than the benefits. EPA should analyze whether alternative regulatory structures—in light of all quantified and unquantified benefits—would better maximize net benefits.

Response: In conjunction with all of the comments received on the proposal, EPA has re-evaluated the options. See the Regulatory Impact Analysis for the analysis of the options for the final rule.

With regard to the regulatory options selected, EPA conducted a beyond-the-floor analysis as required under the CAA and selected one beyond-the-floor standards, the energy assessment, as a cost-effective option for reducing HAP emissions from industrial, commercial, and institutional boilers and process heaters.

Projection of New Units

Commenter Name: Charles McRae
Commenter Affiliation: Rex Lumber
Document Control Number: EPA-HQ-OAR-2002-0058-1846
Comment Excerpt Number: 2

Comment: The limits are so unreasonable that the impact analysis in the rule assumes that no new biomass boilers will ever be built at major sources. This is absurd given the fact that biomass is greenhouse gas-neutral and the government is pushing increased use of renewable energy.

Response: See the response to comment EPA-HQ-OAR-2002-0058-1597.1, excerpt 5.

Commenter Name: Thomas P. Greene, III
Commenter Affiliation: Atlantic Wood Industries, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-1599.1
Comment Excerpt Number: 4

Comment: The limits in the rules as proposed are not achievable. I believe that the limits are so unreasonable that the impact analysis in the rule assumes that no new biomass boilers will ever be built at major sources. This is absurd given the fact that biomass is greenhouse-gas neutral and the government is encouraging the increased use of biomass as a renewable energy.

Response: See the response to comment EPA-HQ-OAR-2002-0058-1597.1, excerpt 5.

Commenter Name: A. Daniel White
Commenter Affiliation: T.R. Miller Mill Company, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-1597.1
Comment Excerpt Number: 5

Comment: The limits are so unreasonable that the impact analysis in the rule assumes that no new biomass boilers will ever be built at major sources. This is absurd, given the fact that biomass is greenhouse gas-neutral and the government is pushing increased use of renewable energy.

Response: It is necessary to note that the limits were not a factor in projecting the number of new major source biomass units. Rather, projections were based on the economic outlook of the biomass energy sector and the applicability of the Utility NESHAP and area source boiler rule. The EPA recognizes ongoing projects and funding supporting biomass as a form of renewable energy and new biomass boilers would be built, but EPA does not expect this growth to fall under the major source category. Please see the response to comment EPA-HQ-OAR-2002-0058-2805.1, excerpt 1 for details on the projection analysis.

Commenter Name: Houston Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1876
Comment Excerpt Number: 58

Comment: The Boiler MACT concludes there will be no biomass boilers constructed major sources. That would be an absurd result, given the government's push for renewable energy.

Response: See the response to comment EPA-HQ-OAR-2002-0058-1597.1, excerpt 5.

Commenter Name: Fred T. Simpson
Commenter Affiliation: Scotch Gulf Lumber, LLC
Document Control Number: EPA-HQ-OAR-2002-0058-1899.1
Comment Excerpt Number: 1

Comment: The emission limits proposed in Boiler MACT are so unreasonable that the impact analysis in the rule assumes that no new biomass boilers will ever be built at major sources. This is absurd given the fact that biomass is greenhouse gas-neutral and the government is pushing increased use of renewable energy.

Response: See the response to comment EPA-HQ-OAR-2002-0058-1597.1, excerpt 5.

Commenter Name: Jim Hickman
Commenter Affiliation: Langdale Forest Products Co.
Document Control Number: EPA-HQ-OAR-2002-0058-2065.1
Comment Excerpt Number: 4

Comment: The limits are so unreasonable that the impact analysis in the rule assumes that no new biomass boilers will ever be built at major sources. This is absurd given the fact that biomass is greenhouse gas-neutral and the government is pushing increased use of renewable energy.

Response: See the response to comment EPA-HQ-OAR-2002-0058-1597.1, excerpt 5.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 27

Comment: The Regulatory Impact Analysis report projects no costs for new biomass or coal units, based on Department of Energy projections. Given the forest products industry's move away from fossil fuel firing and toward biomass, the many state programs mandating renewable energy portfolio standards, our knowledge of several biomass boiler projects under development or consideration, and the trend toward bio-based fuels and bio-based materials production, we do not believe that there will be no new biomass projects in the next few years (unless the new source standards remain so stringent that boiler manufacturers are unable to guarantee compliance with the new source emission limits, as indicated in the Metso comments included in Appendix F). In addition, boilers in many industries are aging and it may not be feasible or cost effective to retrofit these boilers to comply with the rule, necessitating construction of replacement boilers if the facility economics remain viable such that the facility is not closed.

EPA should re-evaluate this component of the RIA and include projected costs for new solid-fuel boilers.

Response: See the response to EPA-HQ-OAR-2002-0058-2805.1, excerpt 1 regarding biomass plants in development and the response to comment EPA-HQ-OAR-2002-0058-2792.1, excerpt 148 regarding the replacement of older boilers.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA)
Document Control Number: EPA-HQ-OAR-2002-0058-2960.1
Comment Excerpt Number: 220

Comment: In 2003 and in the current rulemaking, the estimate of the number of new sources was derived from Department of Energy projections on fuel expenditures. The vast differences between the two estimates are unexplained. However, at a minimum this approach fails to account for the large number of new units that will have to be constructed to replace existing units because the existing units cannot comply with this rule. Constructing a replacement unit, rather than adding controls to an existing unit adds significant costs and burdens because the new unit is presumably subject to the new source requirements rather than the existing source requirements and because an entire new boiler and process heater must be constructed, not just some incremental facilities. As we discuss in comment 1 above, we think replacement of boilers and process heaters will be prevalent because the existing units cannot be retrofitted with the required controls due to space and structural concerns.

Recommendation: Reconcile the 2003 and 2008 estimates of new units.
Recommendation: Adjust the new unit estimate for the need to replace many existing units in order to try to meet the proposal requirements for existing units.

Response: The reason for the difference in projections for new major source boilers between the vacated boiler rule and the proposed rule are attributable to the economic climate and energy demand projected by the Department of Energy Annual Energy Outlook at the time of the vacated standard and today. When the projections for the vacated rule were calculated the economic growth rate was much higher and in turn there were larger estimates for fuel and energy use. Compare that to now where the economy is more stagnant and energy consumption growth rates are flat. The method of estimating new units was the same for the vacated 2004 rule and the 2008 proposal, but the inputs to the methodology were different. Projecting the numbers of boilers which would replace their older units due to space and structural concerns, and making an estimate based on reasonable assumptions would require additional data which the EPA does not have. No specific details were provided by the commenters to support their recommendation.

Commenter Name: Craig Harper

Commenter Affiliation: Collum's Lumber Products, LLC
Document Control Number: EPA-HQ-OAR-2002-0058-2681.1
Comment Excerpt Number: 5

Comment: The limits are so unreasonable that the impact analysis in the rule assumes that no new biomass boilers will ever be built at major sources. This is absurd given the fact that biomass is greenhouse gas-neutral and the government is pushing increased use of renewable energy.

Response: See the response to comment EPA-HQ-OAR-2002-0058-1597.1, excerpt 5.

Commenter Name: Leslie Sue Ritts
Commenter Affiliation: National Environmental Development Association's Clean Air Project NEDA/CAP
Document Control Number: EPA-HQ-OAR-2002-0058-2794.1
Comment Excerpt Number: 15

Comment: EPA has not included costs for new biomass projects because EPA believes that no such units will be built (possibly because the proposed standards are too stringent to allow their development – a result wholly incompatible with state and federal greening initiatives).

Response: See the response to comment EPA-HQ-OAR-2002-0058-1597.1, excerpt 5.

Commenter Name: Christy Sammon
Commenter Affiliation: Southeast Lumber Manufacturers Association
Document Control Number: EPA-HQ-OAR-2002-0058-2727.1
Comment Excerpt Number: 19

Comment: The proposed rule concludes that no new biomass boilers will ever be constructed at major sources in the United States as a result of the stringency of the rules. Given the government's push for the use of renewable energy, this outcome would be absurd. A greenhouse-gas-neutral fuel would be turned into a waste which would degrade into methane gas creating 21 times the global warming potential when compared to its combustion as fuel. Solar and wind are not reliable renewable energy sources in the southeastern United States, so biomass provides the only viable option for renewable energy in this part of the country.

Response: See the response to comment EPA-HQ-OAR-2002-0058-1597.1, excerpt 1.

Commenter Name: Rachel Smolker
Commenter Affiliation: Biofuelwatch

Document Control Number: EPA-HQ-OAR-2002-0058-2805.1
Comment Excerpt Number: 1

Comment: Projections for Increase in Biomass to Energy Generation.
EPA's projections of biomass buildout, as reflected in the cost estimate portion of the Major Source rule, appear to rely on an April 2010 memo from ERG where ERG actually projects a decline in biomass power generation by 2015. [Memo from Graham Gibson, ERG to Jim Eddinger, EPA. New Unit Analysis Industrial, Commercial, and Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants – Major Source. April, 2010]. EPA seems incognizant of the actual number of biomass plants and biomass co-firing projects currently proposed and in permitting, or the amount of biomass power that the Energy Information Administration projects will come online under both business-as-usual scenarios and scenarios where renewable energy is promoted at the federal level. 2[Environmental Working Group, 2010. Clear Cut Disaster. Washington, DC.]. According to industry data, current proposals for biomass power will virtually double the existing capacity for electric generation from biomass, adding an additional 5830 MW, which may be a conservative estimate given increased number of co-firing applications. Current estimates for pending applications in Ohio range from 1200-1600 MW, permit applications. [EL-REN applications approved and pending before the Public Utilites Commission of Ohio July 30,2010.http://www.puco.ohio.gov] Combined permits for Florida and Georgia are roughly an additional 1200 M W. With the amount of biomass power due to come online in the next five years, it is significant that in many respects, the MACT standards proposed for biomass boilers are not as stringent as those proposed for coal-fired boilers.

Response: With regard to the referenced Environmental Working Group document, it does reference 118 new biomass power plant proposals; however, information on size of the boilers and how many are co-fired versus dedicated biomass plants is not provided. For the Ohio, Florida, and Georgia permits cited in the comment, details on if the units are co-fired or dedicated biomass is also not provided. This information is important because the referenced co-fired boilers could fall under the Utility NESHAP rule or be classified as either an area or major source under the Boiler NESHAP. Without details an estimate for applicable new major source biomass boilers is difficult.

EPA conducted additional research into biomass projections using data from the Energy Information Administration's (EIA) April 2009 report An Updated Annual Energy Outlook 2009 Reference Case Reflecting Provisions of the American Recovery and Reinvestment Act (ARRA) and Recent Changes in Economic Outlook and The Handbook of Biomass Combustion and Co-Firing published in 2008. Three sectors for biomass use are provided; commercial biomass, industrial biomass, and electric power (dedicated and co-fired biomass). Projections for 2008 to 2013 are flat for commercial biomass and show a slight decrease for industrial biomass. Within the electric power sector the projections show an increase in growth for both dedicated and co-fired biomass plants. Many co-fired plants in the electric power sector would be covered under the Utility boiler NESHAP. For dedicated biomass plants, based on data received during the comment period these biomass boilers would be classified as area sources of HAP. Comparing the projections for growth of dedicated biomass plants in the EIA report (.08 quadrillion Btu/yr) versus the area source new unit projection analysis for the boiler rule (.06 quadrillion Btu/yr) shows that projecting only new area source boilers is realistic. The methodology for projecting new boilers is discussed in further detail in the memorandum "Revised New Unit Analysis Industrial, Commercial, and Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants – Major Source (2011".

With regard to the limits of biomass boilers versus coal boilers, the EPA thanks the commenter for their concern but has based the MACT limits off the data available for each subcategory.

Commenter Name: David P. Tenny
Commenter Affiliation: National Alliance of Forest Owners
Document Control Number: EPA-HQ-OAR-2002-0058-2750.1
Comment Excerpt Number: 12

Comment: Notably, EPA's own Regulatory Impact Analysis, at page 3-2, estimates zero new biomass units. Discouraging current or new enterprises from using biomass would be inconsistent with the CAA's emissions reduction goals.

Response: See the response to comment EPA-HQ-OAR-2002-0058-1597.1, excerpt 5.

Commenter Name: Tracy Smith
Commenter Affiliation: Coastal Forest Products
Document Control Number: EPA-HQ-OAR-2002-0058-2872.1
Comment Excerpt Number: 14

Comment: The proposed rule concludes that no new biomass boilers will ever be constructed at major sources in the United States as a result of the stringency of the rules. Given the government's push for the use of renewable energy, this outcome would be absurd. A greenhouse-gas-neutral fuel would be turned into a waste which would degrade into methane gas creating 21 times the global warming potential when compared to its combustion as fuel. Solar and wind are not reliable renewable energy sources in the southeastern U.S., so biomass provides the only viable option for renewable energy in this part of the country.

Response: See the response to comment EPA-HQ-OAR-2002-0058-1597.1, excerpt 5 and EPA-HQ-OAR-2002-0058-2727.1, excerpt 19.

Commenter Name: Gary Melow
Commenter Affiliation: Michigan Biomass
Document Control Number: EPA-HQ-OAR-2002-0058-2776.1
Comment Excerpt Number: 21

Comment: As shown in Tables 10 and 11 (75 FR at 32037 and 32038), EPA has estimated the cost of compliance and the environmental benefits for new biomass units and coal units to be zero as listed in Table 11. This implies EPA does not believe there will be any new major biomass or coal plants built or reconstructed. We are aware of several biomass power plants in the development phase, which may or may not be major HAP sources. Certainly, even smaller biomass boiler projects may occur at existing major HAP sources. Federal energy policy encourages the use of renewable energy and several studies show biomass being a significant portion of new renewable energy sources. Therefore the costs cannot be zero going forward, and neither can the environmental benefits of biomass, which include emission offsets from fossil fuels, including greenhouse gases.

Response: See the response to EPA-HQ-OAR-2002-0058-2805.1, excerpt 1 regarding biomass plants in development and the response to comment EPA-HQ-OAR-2002-0058-1597.1, excerpt 5 regarding biomass projections from a renewable energy perspective.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 148

Comment: The RIA report projects no costs for new biomass or coal units, based on Department of Energy (DOE) projections. However, there are a number of reasons why DOE and EPA projections are wrong. Given the many state programs mandating renewable energy portfolio standards, we do not believe that there will be no new biomass projects in the next few years (unless the new source standards remain so stringent that boiler manufacturers are unable to guarantee compliance with the new source emission limits). In addition, the RIA failed to consider that solid-fuel boilers in many industries are aging and it may not be feasible or cost effective to retrofit these boilers to comply with the rule, necessitating construction of replacement boilers. EPA should re-evaluate this component of the RIA and include projected costs for new solid-fuel boilers.

Response: Looking in the near-term, it is difficult to project how many boiler operators would opt to construct a new boiler to replace their older one and estimate the associated costs. EPA’s analysis of new boilers is based on energy demand projections and estimates of boiler replacement rates due to age is outside the scope of this estimate. Furthermore, specific details were not provided by the commenter to incorporate into the estimate. Please see the response to comment EPA-HQ-OAR-2002-0058-2805.1, excerpt 1 for details on the projection analysis.

Other - Impact Analysis

Commenter Name: Peter Maki
Commenter Affiliation: Missouri Fuels for Schools Project
Document Control Number: EPA-HQ-OAR-2002-0058-0847
Comment Excerpt Number: 1

Comment: The Missouri Fuels for Schools Project is funded through a $6 million ARRA grant from the Forest Service to help schools install and operate boiler systems that use woody biomass from local public and private land to heat and/or cool their facilities. This technology should help reduce dependence on fossil fuels, reduce energy costs, create or retain jobs and support healthy forests and the state's forest industry. Seven southern Missouri schools have been selected to have wood-chip heating systems, using efficient, low-emission boilers. Should there be requirements to have costly stack emission tests on a regular basis, there would be no savings to the schools and no reason to change from their existing fossil fuel heating systems. The EPA should instead focus on existing inefficient, polluting stoves. [See DCN:EPA-HQ-OAR-2002-0058-0847.1 for explanation of Missouri Fuels for Schools Project]

Response:

Commenter Name: Peter Maki
Commenter Affiliation: Missouri Fuels for Schools Project
Document Control Number: EPA-HQ-OAR-2002-0058-0847.1
Comment Excerpt Number: 1

Comment: The Missouri Department of Conservation (MDC), in cooperation with the USDA Forest Service's State& Private Forestry program, recently awarded almost $6 million in grants to seven public schools for "Fuels for Schools" projects. The grants are being funded through The American Recovery and Reinvestment Act (ARRA).

Grant recipients and amounts are:

Southern Reynolds R-II School District: $970,000

Perry County 32 School District: $970,000

Steelville R-III School District (Crawford County): $900,000

Rolla 31 School District Junior High Building (Phelps County): $760,000

Gainesville R-V School District (Ozark County): $970,000

Eminence R-I Elementary (Shannon County): $350,000

Mountain View-Birch Tree Liberty High School (Howell County): $850,000

“Fuels for Schools funds will help these schools and school districts install and operate boiler systems that use woody biomass from local and private forest land to heat and/or cool their facilities, “explained grant administrator John Tuttle, Forestry Field Programs supervisor for the MDC. “This technology should help reduce dependence on fossil fuels, reduce energy costs, create or retain jobs and support healthy forests and the state’s forest industry.”

The Fuels for Schools projects will help create a stronger market for woody material historically considered waste, such as unhealthy or small-diameter trees and wood debris left from logging,” he added. “These forest products currently have little or no commercial value so the Fuels for Schools projects can provide micro-markets for wood chips produced from them.” Tuttle explained that the projects also will support forest health, a key part of the MDC’s mission, by making it economical to thin overcrowded forest stands and remove diseased and insect-infested trees.

According to the Fuels for Schools and Beyond website (www.fuelsforschools.info), “In general, fuel cost savings for projects that have replaced natural gas boiler systems have averaged at 25% while facilities replacing fuel oil systems have enjoyed savings of 50-75%.”

What makes this technology so attractive to a school is the fuel cost savings the school will have in this era of tight budgets. The average fuel savings we calculate for the seven schools is 67%. A school such as Steelville, for example, will see its average fuel cost drop from $61,953 per year to $20,599 per year. Since the price of wood chips has been stable, unlike fossil fuel prices, there will be years when calculated savings will be more. Wood chips are our cheapest fuel at $3.25 per million BTU’s, compared to propane at $15.00 per million BTU’s, or electric heat at $25.00 per million BTU’s.

Other benefits of wood-chip heating systems, is that the technology we are using allows for over 80% burn efficiencies. These systems have minimal emissions compared to what the schools presently use. When wood biomass replaces fossil fuels, there is a net reduction in greenhouse gas emissions.

Response:

Commenter Name: C. Finley McRae
Commenter Affiliation: Rex Lumber
Document Control Number: EPA-HQ-OAR-2002-0058-1848
Comment Excerpt Number: 1

Comment: I want to bring to your attention the damage that your proposed rules regarding Boilers will have on our businesses. We employ over 125 people at each of our locations (2, soon to be 3) and these rules have the potential to shut us down and cause the loss of all those jobs. The cost to meet the unreasonable requirements in these rules may cause us to decide it is not worthwhile to operate. Do you realize these limits are unattainable and will cause no new biomass boilers to be built? The President’s has been promoting alternative energy to offset fossil fuels and we have been effectively using biomass in the forest products industry for years, these rules are a direct contradiction to the President's goals.

Response:

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute and National Petrochemical and Refiners Association
Document Control Number: EPA-HQ-OAR-2002-0058-0851.1
Comment Excerpt Number: 15

Comment: In stark contrast to the ICR cost estimates above, page 3-1 and 3-2 of the RIA (EPA-HQ-OAR-2002-0058-0810) indicates "The resulting total national cost impact of the proposed rule is 10.0 billion dollars in capital expenditures and 3.2 billion dollars per year in total annual costs. Considering estimated fuel savings resulting from work practice standards and combustion controls, the total annualized costs are reduced to 2.9 billion.

Using Department of Energy projections on fuel expenditures, the number of additional boilers that could be potentially constructed was estimated. The resulting total national cost impact of the proposed rule in the 3rd year is 17 million dollars in capital expenditures and 6.2 million dollars per year in total annual costs, when considering a 1 percent fuel savings.

Even the RIA estimate is significantly low for the following reasons (in addition to the significant underestimate of the number of sources discussed in Item 1).

There is no basis for the assumed 1% energy credit. Major sources already manage their energy use as a cost control measure and overlaying an Energy Star program on existing programs is unlikely to provide any benefits at major sources. Furthermore, all of the additional controls required for complying with this rule consume energy. Thus, this rule will be a net energy consumer not an energy saver.

Additionally, the proposal rightfully does not require implementing audit results and does not include costs and burdens for doing so. Thus, there is no basis for assuming the audit requirement saves any energy.

Response:

Commenter Name: Randolph Price
Commenter Affiliation: Consolidated Edison Company of New York
Document Control Number: EPA-HQ-OAR-2002-0058-1869.1
Comment Excerpt Number: 2

Comment: A review of the proposed rulemaking record suggests that EPA's identification of the combustion units that comprise the population of "Major Source Boilers and Process Heaters" within the United States is inconsistent. For example, page 3 of the April 2010 ERG Memorandum ["MACT Floor Analysis (2010) for the Industrial, Commercial, and Institutional Boilers and Prodess Heaters NESHAP-Major Source"] states "there are 13,555 boilers/process heaters currently in operation at major sources in the United States." However, Table 1 of Part B of the Supporting Statement for Information Collection Request No. 228 6.01 (ICR) indicates that there are 13,052 such combustion units, and Page 4 of the March 2010 ERG Memorandum ["Methodology for Estimating Impacts from Boilers and Process Heaters at Major Sources of HAPs"] indicates that there is "a total of 13,434 unique boilers and process heaters" in the United States.

Response:

Commenter Name: Arlington Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1779
Comment Excerpt Number: 110

Comment: If this rule remains in its current form, SKF's plans to invest $300 million in two industrial scale projects converting both its U.S. mill operations to renewable biomass cogen facilities will be lost. The new facilities would include bubbling fluidized bed boiler system and condensing extraction turbine generators designed to produce approximately 31 megawatts of renewable electricity for the region and also supplying the facilities' thermal requirements, replacing natural gas.

The cogeneration facilities would be fueled 100 percent by woody biomass or a combination of wood and recycled pulp mill residue. Significant investments have been made in both states to secure proper engineering and design, environmental permitting, electrical interconnection, and fuel availability studies.

The two projects would take approximately two and a half years to complete and include the hiring of 400 contract employees to help in construction, with an additional 60 employees hired for operation of the facility.

The local logging and trucking industry can expect to see an additional 200 jobs to carry the increased load. We want to continue with this project.

Response:

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)

Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 11

Comment: The estimate of the number of boiler and process heaters impacted by this proposal may be significantly understated. The 1993 proposal for the vacated Boiler and Process Heater NESHAP estimated at 68 FR 1687 (January 13, 2003) that there would be a total of 58,200 affected existing units versus the current estimate of 13,555, suggesting an under-counting by more than a factor of 4. That original estimate was based on input from a vast number of sources during the Industrial Combustion Coordinated Rulemaking (ICCR) effort. Similarly, the 1993 proposal estimated 3463 new units per year rather than the 46 units per year estimated here. The RIA for that rulemaking [Footnote: EPA-452/R-04-002 (February 2004)] details the development of their estimate in Section 3. EPA should explain how they have reconciled the large difference in the estimates of existing units between the two phases of this rulemaking and re-visit its boiler inventory as appropriate.
* The RIA [Footnote: EPA-HQ-OAR-2002-0058-0810] reports there are 199 existing units nationally that fire Gas 2 (gases other than natural gas and refinery gas). This is clearly an unreasonably low number. The American Petroleum Institute has indicated that their members alone account for more than 180 boilers and process heaters in Gas 2 service at major sources [Footnote: EPA-QH-OAR-2002-0058-0851]. Since the RIA estimates, in Table 3-1, annualized O&M costs of $500 million per year for just these 199 units, there is a large impact from underestimating their number.
* AF&PA knows of several forest products companies that did not receive an ICR in 2008 and their boilers are not included in the Boiler MACT database. We expect that there are other industries where facilities did not receive an ICR and are not counted in EPA's inventory of major source boilers.

Response:

Commenter Name: Marvis A. Lewallen
Commenter Affiliation: Clearwater Paper
Document Control Number: EPA-HQ-OAR-2002-0058-2862
Comment Excerpt Number: 2

Comment: Overly burdensome regulation will increase greenhouse gas emissions. The definitive study assessing the use of biomass to generate electricity is the May 2008 report entitled Bioenergy and Greenhouse Gases, prepared by Gregory Morris, PhD of The Renewable Energy Program of the Pacific Institute in Berkeley, California. This report notes that the use of biomass avoids the need to combust fossil fuels and also notes that because the combustion of biomass adds no net new carbon to the atmospheric-biospheric circulation system, it is considered “carbon neutral.” Additionally, the study went beyond these comparatively simplistic conclusions to evaluate whether and how the change in terrestrial biomass (i.e., forest thinning) affects overall sequestration as well as the impacts of the change in timing and mix of carbon forms that occur depending on the fate of biomass. This detailed analysis concludes that greenhouse gas sequestration is enhanced by the forest thinning that generates much slash. Of greater importance, however, is the benefit achieved by avoiding open burning and/or decomposition (composting) of slash. Open burning and low-efficiency combustion (i.e., fireplaces) result in much higher emissions of methane, a potent greenhouse gas, as compared to controlled combustion in a boiler. Biomass that is left to decompose in the forest or is land filled degrades into a 50-50 mixture of methane (CH_4) and carbon dioxide (CO_2). The report notes that due to the much higher global warming potential of methane, as compared to carbon dioxide, the global warming impacts associated with decomposition exceed those of controlled combustion even though less carbon is released into the atmosphere from natural decomposition over a 100-year period. In summary, Dr. Morris' team concluded that for every ton of biomass combusted to make electricity, you avoid 0.8 tons of greenhouse gas (CO_2- equivalent) as a result of avoided fossil fuel use. For the biomass originating as slash, there is an additional net reduction of greenhouse gases of between 0.22 tons and 2.28 tons, depending on how the slash would have been handled if it had not been routed to controlled combustion. [Reference: Morris; Bioenergy and Greenhouse Gases, Table 4, Green Power Institute of The Renewable Energy Program of the Pacific Institute, May 2008]. This means that by combusting biomass our facilities reduce GHGs by 1.42 tons for every bone dry ton of slash that they combust.

Therefore, we strongly urge EPA to consider the comments below on how to revise the Boiler and Process Heater NESHAP so as to minimize the potential for boiler closures. It is not economical to haul biomass long distances. The closure of any biomass boiler will have the immediate impact of increasing the amount of biomass that is disposed of through open burning and/or land filling. This will have the exact opposite effect that EPA is hoping for through promulgation of the NESHAP.

Response:

Commenter Name: Marvis A. Lewallen
Commenter Affiliation: Clearwater Paper
Document Control Number: EPA-HQ-OAR-2002-0058-2862
Comment Excerpt Number: 3

Comment: It is not uncommon to have combustion devices below 10 MMBtu/hr heat input at forest product manufacturing facilities. These can be natural gas or propane fired heaters that transfer heat to process equipment through a sealed oil system or they can be water heaters that are larger than 120 gallons and so do not fit within the exemption in the proposed rules. The courts have long established the concept that EPA does not need to concern itself with trivial matters. See, e.g., Alabama Power. This concept is the basis for such things as the exemption of insignificant emissions increases under the major new source review program. The D.C. Circuit has repeatedly upheld EPA's discretion to carve out insignificant emissions source from regulation. Notwithstanding this latent authority, EPA has proposed to regulate all sorts of de minimis boilers and process heaters. We strongly urge EPA to exempt all units with a heat input of less than 10 MMBtu/hr regardless of fuel or unit type. This approach is consistent with the approach taken for the last 30+ years under the NSPS program.

Response:

Commenter Name: Marvis A. Lewallen
Commenter Affiliation: Clearwater Paper
Document Control Number: EPA-HQ-OAR-2002-0058-2862
Comment Excerpt Number: 4

Comment: EPA has proposed to mandate energy efficiency audits as a beyond the floor requirement. We do not believe that EPA has justified the basis for requiring beyond the floor requirements and strongly urge EPA to drop this requirement. While we are in favor of energy efficiency, this imposes an undue burden, particularly in relation to those of our facilities that are in distant locations and for which obtaining the necessary persons to conduct such an audit is difficult and expensive.

Response:

Commenter Name: Arthur Blazer
Commenter Affiliation: Council of Western State Foresters
Document Control Number: EPA-HQ-OAR-2002-0058-2832.1
Comment Excerpt Number: 6

Comment: Avoid emission limits for new and existing sources that prevent the use of clean, renewable biomass. As proposed, this rule sets overly stringent emission limits for mercury, dioxin and hydrochloric acid which are present in very small amounts in wood. The costs to achieve these limits will significantly penalize new and existing biomass burning facilities and should be dropped or replaced by alternative work practices standards (for dioxin and mercury). The

proposed limits could require facilities to adopt costly new control equipment which would encourage the use of other non-renewable fuel sources. Emission limits for CO should not be overly stringent so as to discourage the conversion of coal-fired facilities to woody biomass feedstocks or the construction of new wood-based bioenergy facilities.

Response:

Commenter Name: Jennifer Klein
Commenter Affiliation: Ohio Chamber of Commerce
Document Control Number: EPA-HQ-OAR-2002-0058-2901.1
Comment Excerpt Number: 9

Comment: Biomass is a "clean" fuel in many of the same respects as the Gas 1 fuels. Perhaps more importantly, biomass-fired boilers produce no net GHG emissions, making the combustion of biomass an important tool in managing and reducing the nation's carbon footprint. Similarly, biomass is an abundant, renewable domestically-produced fuel that can help reduce reliance on foreign sources of fossil fuel and, thus, improve the nation's energy security. Prescribing stringent HAP emissions limitations on biomass boilers will create a significant barrier to the continued use and expansion of biomass fuels.

Response:

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 129

Comment: The estimate of the number of boiler and process heaters impacted by this proposal may be significantly understated. The 1993 proposal for the vacated 2004 Boiler rule estimated at that there would be a total of 58,200 affected existing units versus the current estimate of 13,555, suggesting an under-counting by more than a factor of 4.160[68 Fed. Reg. 1687 (January 13, 2003).] That original estimate was based on input from a vast number of sources during the Industrial Combustion Coordinated Rulemaking (ICCR) effort. Similarly, the 1993 proposal estimated 3,463 new units per year rather than the 46 units per year estimated here. The RIA for that rulemaking details the development of their estimate in Section 3. EPA should determine the cause for this large discrepancy in the number of affected units and explain it.

Response:

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 130

Comment: The RIA reports there are 199 existing units nationally that fire Gas 2 (gases other than natural gas and refinery gas). This is clearly an unreasonably low number. The American Petroleum Institute has stated that its members alone account for more than 180 boilers and process heaters in Gas 2 service at major sources. One ACC member alone has 25 Gas 2 units. Since the RIA estimates annualized O&M costs of $500 million per year for just these 199 units, there will be a large impact on the estimated cost from underestimating their number. EPA should re-evaluate its boiler inventory.

Response:

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 131

Comment: ACC is aware of major HAP sites that did not receive a Phase I or Phase II ICR and whose combustion units are, therefore, not included in the EPA database. This further supports our position that EPA has understated the cost and impact of the rule. EPA should re-evaluate its boiler inventory.

Response:

Executive Orders

Executive Order 12866, Regulatory Planning and Review

Commenter Name: Ben Brandes
Commenter Affiliation: National Mining Association
Document Control Number: EPA-HQ-OAR-2002-0058-2787.1
Comment Excerpt Number: 1

Comment: EPA has undertaken a far-reaching regulatory program that is apparently designed to reduce the use of coal throughout the American economy. The coordinated nature of this program is most evident in the electric power sector, which EPA has undertaken to transform. Upon taking office, the EPA Administrator formulated seven priorities, one of which was to "develop a comprehensive strategy for a cleaner and more efficient power sector, with strong but achievable reduction goals for SO2, NO2, mercury and other air toxics." [Footnote: Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone, 75 Fed. Reg. 45,210, 45,227/3 (August 2, 2010), quoting the EPA Administrator's January 12, 2010 outline of the Agency's seven priorities.]This goal was reiterated by EPA in its recently proposed Transport Rule, where the Agency said that "[i]n furtherance of this priority goal, and to respond to statutory and judicial mandates, EPA is undertaking a series of regulatory actions over the course of the next 2 years that will affect the power sector in particular." [Footnote: Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone, 75 Fed. Reg. 45,210, 45,227/3 (August 2, 2010), quoting the EPA Administrator's January 12, 2010 outline of the Agency's seven priorities.]

These EPA rulemakings include:

The recently completed National Ambient Air Quality Standards (?NAAQS?) for sulfur dioxide (‘sO2?) and nitrogen dioxide (?NO2?);

The currently proposed new ozone NAAQS and the soon-to-beproposed new PM2.5 NAAQS;

The proposed Transport Rule and expected additional transport rules for the 1997 ozone NAAQS;

The soon-to-be-proposed MACT standards for electric generating units (?EGUs?);

EPA‘s greenhouse gas (?GHG?) regulation under the Prevention of Significant Deterioration (?PSD?) program;

The soon-to-be-proposed New Source Performance Standards for EGUs (including GHG NSPS);

Best Available Retrofit Technology (“BART”) standards for EGUs;

The proposed regulations for coal combustion residues; and

The soon-to-be-proposed water quality regulations for cooling intake structures and soon-to-be-proposed effluent guidelines for discharges from power plants.

Recognizing that all of these regulations are implementing a single overall priority goal and constitute a “comprehensive set of requirements,” [Footnote: Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone, 75 Fed. Reg. 45,210, 45,227/3 (August 2, 2010), quoting the EPA Administrator‘s January 12, 2010 outline of the Agency‘s seven priorities.] EPA pledged to coordinate at least its power sector air quality regulations and, to the extent it could under relevant statutory law, to coordinate these power sector air quality regulations with the coal combustion residue regulations and the two power sector water quality regulations. [Footnote: Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone, 75 Fed. Reg. 45,210, 45,227/3 (August 2, 2010), quoting the EPA Administrator‘s January 12, 2010 outline of the Agency‘s seven priorities.] EPA further pledged to “engage with other federal, state and local authorities, as well as with stakeholders and the public at large, with the goal of fostering investments in compliance that represent the most efficient and forward-looking expenditure of investor, shareholder, and public funds, resulting, in turn, in the creation of a clean, efficient, and completely modern power sector.” [Footnote: Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone, 75 Fed. Reg. 45,210, 45,227/3 (August 2, 2010), quoting the EPA Administrator‘s January 12, 2010 outline of the Agency‘s seven priorities.]

Response: See section 7.2 of the Regulatory Impacts Analysis (RIA) for discussion of cumulative impacts.

Commenter Name: Ben Brandes

Commenter Affiliation: National Mining Association
Document Control Number: EPA-HQ-OAR-2002-0058-2787.1
Comment Excerpt Number: 3

Comment: News accounts recently reported that EPA is well aware that its regulatory efforts in the power sector will increase the costs to coal-fueled EGUs and make them less competitive with renewable resources. In an article entitled “Administration Eyes EPA Rules To Spur Shift From Coal To Renewables,” it was reported that:

Rob Brenner of EPA‘s Office of Air & Radiation told a July 28 meeting of the agency‘s environmental justice advisers that pending rules to control emissions, waste and water discharges from utilities will not only protect public health but add costs to the industry that might make renewable energy a more viable alternative.

“We need to set health-based standards for power plants, and once we do that then they can compete with some of these renewable sources,” Brenner said at the National Environmental Justice Advisory Committee (NEJAC) meeting in Washington, DC. He added later, ?It‘s not really a fair competition because [coal-fueled power plants] are cheaper than they should be because they’re not controlling their pollutants? to their full extent because EPA is yet to issue key rules for the sector, including a mercury air rule and a plan to regulate coal combustion residue. [Footnote: Administration Eyes EPA Rules to Spur Shift from Coal to Renewables, InsideEPA.com (July 29, 2010), at http://insideepa.com/201007291915893/EPA-Daily-News/Daily-News/administration-eyesepa-rules-to-spur-shift-from-coal-to-renewables/menu-id-95.html.]

The same article reported that the White House also understands that transforming the power sector will inevitably result in reduced use of coal and increased use of renewables. Referring to remarks of Nancy Sutley, Chair of the White House Council on Environmental Quality, the article reported that:

Sutley responded that she doubts the existence of so-called clean coal. “Other people have labeled it ?clean coal,” she said. “I don’t know if I would necessarily
concede that that is real. . . . I think in the long run, not just for the [United States] but for the world, that developing and making sure that there is access to these inherently cleaner sources of energy is important. . . . . We need to use energy more efficiently and more cleanly.” [Footnote: Administration Eyes EPA Rules to Spur Shift from Coal to Renewables, InsideEPA.com (July 29, 2010), at http://insideepa.com/201007291915893/EPA-Daily-News/Daily-News/administration-eyesepa-rules-to-spur-shift-from-coal-to-renewables/menu-id-95.html.]

Response: See section 7.2 of the Regulatory Impacts Analysis (RIA) for discussion of cumulative impacts.

Commenter Name: Ben Brandes
Commenter Affiliation: National Mining Association

Document Control Number: EPA-HQ-OAR-2002-0058-2787.1
Comment Excerpt Number: 4

Comment: Other EPA regulatory proposals are also part of an overall strategy to reduce the use of coal throughout the economy. This strategy includes the Boiler MACT and Area Source rule at issue here. In the regulatory preamble to the Boiler MACT rule proposal, EPA stated forthrightly that its reason for proposing strict MACT standards for coal boilers and process heaters but only work practice standards for natural gas boilers was to incentivize operators of coal-fueled boilers to switch to natural gas and to discourage operators of natural gas-fueled boilers from switching to coal. [Footnote: National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters, 75 Fed. Reg. 32,006, 32,025/3 (June 4, 2010).] In discussing this issue, EPA made plain that it considers coal to be a "dirty" fuel whose use is inconsistent with the CAA and therefore should be discouraged. [Footnote: National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters, 75 Fed. Reg. 32,006, 32,025/3 (June 4, 2010).] In contrast, EPA considers natural gas to be a "clean fuel" whose use should be encouraged at coal's expense. According to EPA:

In addition, emission limits on gas-fueled boilers and process heaters may have the negative effect of providing an incentive for a facility to switch from gas (considered a "clean" fuel) to a "dirtier" but cheaper fuel (i.e., coal). [Footnote: National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters, 75 Fed. Reg. 32,006, 32,025/3 (June 4, 2010).]

The coal industry also faces a panoply of prospective regulation of the process of producing coal. These regulations include potentially stricter NAAQS for PM10 which may make western surface mining untenable, new restrictions in Appalachia that could result in major reductions in coal mining in that region, and potential imposition of NSPS standards on mining emissions of PM10, methane, volatile organic compounds, and nitrogen oxides. All of these regulations together—EPA's power sector regulations, its regulations for the use of coal in the manufacturing and commercial sectors, and its regulations of coal mining—all have the potential to combine to cumulatively and dramatically reduce coal usage.

Response: See section 7.2 of the Regulatory Impacts Analysis (RIA) for discussion of cumulative impacts.

Commenter Name: Ben Brandes
Commenter Affiliation: National Mining Association
Document Control Number: EPA-HQ-OAR-2002-0058-2787.1
Comment Excerpt Number: 5

Comment: The effect of each EPA individual rule affecting coal, including the rules at issue here, cannot be understood without a cumulative analysis

Given EPA's intent to transform the power sector from what it is today into something different and given its efforts to reduce coal use throughout the economy, EPA must produce a cumulative and economy-wide assessment of this program. As EPA has proposed and finalized each individual regulation, EPA's impact analysis has been limited to the effect of the specific regulation in question. However, to understand the effect that all the rules together will create, it is necessary to study the effect of that program in total.

These effects could be extremely large. For instance, EPA projects the annual cost of the SO2 NAAQS to be $2.9 billion to $3.0 billion in 2020, with most of those costs associated with the power sector; [Footnote: U.S. Environmental Protection Agency, Final Regulatory Impact Analysis (RIA) for the SO2 National Ambient Air Quality Standards (NAAQS) at 7-4, Table 7.1, June 2010 (Docket ID EPA-HQ-OAR-2009- 0769-0059).] the annual cost of the Transport Rule (all in the EGU sector) to be $3.7 billion in 2012 and $2.8 billion in 2014, [Footnote: 75 Fed. Reg. at 45348/1.]with another $2 billion in 2020 and 2025; [Footnote: 75 Fed. Reg. at 45333, Table V.E-1.] the annual cost of the ozone standard to be $32 – 44 billion, again with much of that cost in the EGU sector; [Footnote: U.S. Environmental Protection Agency, Final Ozone National Ambient Air Quality Standards (NAAQS) Regulatory Impact Analysis at 5-23, March 2008 (Docket ID EPA-HQ-OAR-2005-0161-2849) (estimate for 0.065 ppm standard; EPA's proposal is 0.060-0.070).] and the total costs of the coal combustion residue rule to be over $8 billion under the Subtitle D option and over $20 billion with the Subtitle C option. [Footnote: Hazardous and Solid Waste Management System; Identification and Listing of Special Wastes; Disposal of Coal Combustion Residuals From Electric Utilities, 75 Fed. Reg. 35218, 35134, Table 1 (June 21, 2010).] Despite the request from NMA and others for EPA to assess the cost of its GHG regulatory program, EPA has refused to do so, and so that cost is unknown but could be very substantial as well. The other programs identified above will also add significant cost, with the new EGU MACT standards expected to have a very large impact.

But these estimates, as large as they are, mask the overall effect of the regulations when considered cumulatively. The proposed Transport Rule is an example. EPA's draft Regulatory Impact Analysis (?RIA?) for this proposed rule envisions relatively small impacts to coal usage. EPA projects that EGUs can meet the requirements of the rule by switching from high sulfur to low sulfur coal and by installing pollution control equipment, with the result that EPA estimates the retirement of only 1.2 GW of 'small and infrequently used? coal-fueled generating units by 2014. [Footnote: U.S. Environmental Protection Agency, Regulatory Impact Analysis for the Proposed Federal Transport Rule at 14, June 2010 (Docket ID EPA-HQ-OAR-2009-0491-0078).] Based on the foregoing, EPA projects additional cost to the utility industry of $3.7 billion in 2012 and $2.8 billion in 2014 ($2006). [Footnote: U.S. Environmental Protection Agency, Regulatory Impact Analysis for the Proposed Federal Transport Rule at 31, June 2010 (Docket ID EPA-HQ-OAR-2009-0491-0078).]

NMA will comment on these projections in its comments on the proposed Transport Rule, but for purposes here EPA's projection of almost no impact to the coal industry is not meaningful because it is based on an analysis of the Transport Rule in isolation. Thus, even if EPA's projected assessment of the effect of the Transport Rule on coal is correct, that assessment assumes that there are no other forthcoming EPA regulations that will affect the use of coal, an assumption that is clearly wrong. The control options that the Transport Rule RIA envisions appear to exhaust (and likely go beyond exhausting) the ability of the power sector to absorb EPA regulation without large-scale closings of coal plants. The next regulation following the Transport Rule that adds cost to coal-fueled electric generation therefore will force plant closings, but it is incorrect to say that it was that next regulation and not the Transport Rule that causes the plant closings. Both rules and indeed the entire program cause that effect.

EPA‘s push for replacement of coal with natural gas in the national electricity generation mix, as discussed above, will have severe economic impacts. The American Public Power Association recently published a study evaluating the economic impact of relying more heavily on natural gas to generate electricity. [Footnote: Nicholas Braden, New Study Examines Economic Impacts on Utilities if Carbon Emission Rules Cause Shift from Coal to Natural Gas (Amer. Pub. Power Assn., Wash., D.C.), July 7, 2010 (news release).] It provides insights into the potential cumulative economic impacts of the numerous recent rulemakings, proposed rules and forthcoming proposals that focus on coal-based electricity generation. According to the study, the total cost of replacing all existing coal generation with gas would be $743 billion. The study estimates that the cost of just replacing the existing 335,000 MW of coal-based generation would cost $335 billion. The need for new pipeline and storage capacity would be another major hurdle to this fuel switching and the study estimates this would cost $348 billion. The remainder of the total costs would entail necessary changes in the way natural gas is managed in the U.S. energy system, investment in training new staff to deal with the fuel changes, among other changes in power support structure.

EPA itself recognizes the need for cumulative analysis in an analogous situation. EPA requires that EPA reviewers of Environmental Impact Statements (“EISs”) under the National Environmental Protection Act (“NEPA”) take cumulative impacts into account, including consideration of ?impacts that are due to past, present, and reasonably foreseeable actions.” [Footnote: U.S. Environmental Protection Agency, Consideration of Cumulative Impacts in EPA Review of NEPA Documents (May 1999) at 10.] According to EPA, in assessing environmental impacts, it is necessary to assess “[t]he combined, incremental effects of human activity” rather than just the impacts of the particular action for which federal approval is sought. [Footnote: U.S. Environmental Protection Agency, Consideration of Cumulative Impacts in EPA Review of NEPA Documents (May 1999) at 1.] This is based on the recognition that individual actions “may be insignificant by themselves,” but that cumulative impacts accumulate over time, from one or more sources and these cumulative effects must be taken into consideration. [Footnote: U.S. Environmental Protection Agency, Consideration of Cumulative Impacts in EPA Review of NEPA Documents (May 1999) at 10.]

The Council on Environmental Quality (“CEQ”) also requires cumulative impact analysis in EISs. CEQ regulations require that agencies considering major actions that could affect environmental quality consider the “overall, cumulative impact of the action proposed (and of further actions contemplated).” [Footnote: 35 Fed. Reg. 7390, 7391 (1970). It should be emphasized that CEQ does not distinguish between cumulative analysis of environmental impacts and of socioeconomic impacts. Under CEQ regulations, agencies must examine the effect of the proposed action on the “human environment.” 40 C.F.R. § 1508.14 states that “human environment” shall be interpreted comprehensively to include the natural and physical environment and the relationship of people with that environment.” While “economic or social effects are not intended by themselves to require preparation of an environmental impact statement," "[w]hen an environmental impact statement is prepared and economic or social and natural or physical environmental effects are interrelated, then the environmental impact statement will discuss all of these effects on the human environment." This applies to cumulative analysis: where socioeconomic effects accumulate from multiple actions, they must be assessed cumulatively, just as environmental effects must be assessed cumulatively. Thus, cumulative analysis is as relevant for examining socioeconomics as it is for analyzing environmental impacts.]

EPA's and CEQ's reasons for requiring cumulative impact analysis in EISs apply with equal force to economic analysis that EPA performs of its regulations. Where effects of a proposed action accumulate with those of other related actions, examining the effects of the proposed action in isolation will mask the overall effect of the action. That is as true for EPA's regulatory efforts to reduce coal usage as it is for environmental analysis in the NEPA context. To again cite the proposed Transport Rule as an example, as stated, EPA concludes that the rule will not materially affect the use of coal for electric generation. [Footnote: 75 Fed. Reg. at 45357/1.] But under the rationale of CEQ's NEPA regulations, cumulative impact analysis should be conducted because "[c]umulative impacts can result from individually minor but collectively significant actions taking place over a period of time." [Footnote: 40 C.F.R. 1508.7.]

The same is true for EPA's analysis of the proposed Boiler MACT rule specifically at issue here. EPA's RIA concludes that the rule will have only relatively minor effects on production costs for the sectors of the economy affected. But EPA's analysis is rudimentary and only takes into consideration increased engineering costs and does not examine (at least so far as NMA can tell) fuel-switching. Yet, as stated above, the rule is designed to encourage coal boilers to fuel-switch to gas and to discourage gas-fueled boilers from fuel-switching to coal. Moreover, the proposed rule is just one of a series of rules apparently designed to reduce coal use in the United States. Even if the boiler MACT in and of itself did not significantly affect coal usage (a conclusion that cannot be drawn from the face of the RIA), that result may be masking a much larger effect on coal usage when seen in context of EPA's overall program. Discerning whether that overall effect exists is the central purpose of cumulative impact analysis and the reason why such analysis is required in EISs.

Response: See section 7.2 of the Regulatory Impacts Analysis (RIA) for discussion of cumulative impacts.

Commenter Name: Ben Brandes
Commenter Affiliation: National Mining Association
Document Control Number: EPA-HQ-OAR-2002-0058-2787.1
Comment Excerpt Number: 6

Comment: Executive Order 12866 specifically requires cumulative analysis as follows:

Each agency shall tailor its regulations to impose the least burden on society, including individuals, businesses of differing sizes, and other entities (including small communities and governmental entities), consistent with obtaining regulatory objectives, taking into account, among other things, and to the extent practicable, the costs of cumulative regulations. [Footnote: Exec. Order No. 12,866, 58 Fed. Reg. 51735 (Sep. 30, 1993).]

This requirement for cumulative analysis stems from the regulatory philosophy of Executive Order 12866 that the need for and effects of government regulatory actions should not be examined in isolation but instead on an overall and coordinated basis. The preamble to the Order found that the then current regulatory system did not work in a way that produced efficient results or regulations that were "effective, consistent, sensible, and understandable." [Footnote: Exec. Order No. 12,866, 58 Fed. Reg. 51735 (Sep. 30, 1993).] The first objective of the Order, therefore, was to "enhance planning and coordination with respect to both new and existing regulations." [Footnote: Exec. Order No. 12,866, 58 Fed. Reg. 51735 (Sep. 30, 1993).] In that vein, the main administrative provisions of the Order—an interagency Planning Mechanism, the requirement that each agency produce a Unified Regulatory Agenda and develop a Regulatory Plan, the requirement for a Regulatory Working Group and the provision for quarterly Conferences among OIRA and state, local and tribal governments— were all included to enhance coordination of any specific regulation proposed by an agency with that agency's other existing and contemplated regulations, with other regulations of other agencies, and with the President's overall regulatory priorities. [Footnote: Exec. Order No. 12,866, 58 Fed. Reg. 51735 (Sep. 30, 1993).]

The Statement of Regulatory Philosophy and Principles in Executive Order 12866 also stressed the need for coordination. This Statement provides that "[i]n deciding whether and how to regulate, agencies should assess all costs and benefits of available regulatory alternatives." [Footnote: Exec. Order No. 12,866, 58 Fed. Reg. 51735 (Sep. 30, 1993).] Agencies are instructed to "examine whether existing regulations (or other law) have created, or contributed to, the problem that a new regulation is intended to correct and whether those regulations (or other law) should be modified to achieve the intended goal of regulation more effectively, [Footnote: Exec. Order No. 12,866, 58 Fed. Reg. 51735-36 (Sep. 30, 1993).] to "base its decisions on its best reasonably obtainable scientific, technical, economic, and other information concerning the need for, and consequences of, the intended regulation;" [Footnote: Exec. Order No. 12,866, 58 Fed. Reg. 51736 (Sep. 30, 1993).] and to "avoid regulations that are inconsistent, incompatible, or duplicative with its other regulations or those of other Federal agencies. [Footnote: Exec. Order No. 12,866, 58 Fed. Reg. 51736 (Sep. 30, 1993).] Indeed, the preamble to the Executive Order states that ?[t]he objectives of this Executive order are to enhance planning and coordination with respect to both new and existing regulation...." [Footnote: Exec. Order No. 12,866, 58 Fed. Reg. 51735 (Sep. 30, 1993).]

This requirement for coordinated government action based on coordinated and cumulative analysis built on the same requirement in Executive Order 12291, the predecessor order to Executive Order 12866 and the Order which first required agencies to prepare Regulatory Impact Analyses. Executive Order 12291 required agencies, in promulgating new regulations, to "tak[e] into account the condition of the particular industries affected by regulations . . . and other regulatory actions contemplated for the future.” [Footnote: Exec. Order No. 12,291 at 2(e) (emphasis added).]

The Executive Order 12866 requirements for coordinated and cumulative analysis apply with particular force to EPA‘s efforts to remake the power sector and its apparent effort to reduce coal usage throughout the economy. As shown above, each individual regulation that EPA promulgates in this area, including the Boiler MACT rule and Area Source rule at issue here, is part of a single overall program with cumulative consequences.

Moreover, EPA cannot say that cumulative analysis is not “practicable” within the meaning of section 1(b)(11) of Executive Order 12866. EPA obviously has very sophisticated modeling techniques at its disposal. If in any one rulemaking EPA believes that it cannot anticipate and therefore assess the effects of future rulemakings, EPA can assess a range of possible future regulation. Certainly, the fact that EPA has indicated that it has an overall program in furtherance of one of the Agency‘s seven priorities suggests that EPA has a fairly concrete idea of the range of regulatory outcomes that it anticipates. Alternatively, EPA can delay any particular rulemaking until it has better information about future regulatory requirements that it intends to impose. What EPA cannot do, however, is to follow its current regulatory course, where the Agency analyzes individual rulemaking effects in isolation, as if there is no overall regulatory context.

Response: See section 7.2 of the Regulatory Impacts Analysis (RIA) for discussion of cumulative impacts.

Commenter Name: Ben Brandes
Commenter Affiliation: National Mining Association
Document Control Number: EPA-HQ-OAR-2002-0058-2787.1
Comment Excerpt Number: 8

Comment: The Specific Cumulative Impact Assessment Requested

NMA believes that the cumulative impact assessment should examine the following factors:

Overall impacts on the economy. Specifically, the effect on GDP and jobs. In this regard, some of EPA‘s regulations (in particular, the NAAQS) will not just affect energy but will affect other sectors of the economy as well both directly (for example, through direct regulation of manufacturing sources) and indirectly (for example, through increased energy costs). EPA should examine all reasonably foreseeable effects of its regulations on the overall economy.

Energy. This part of the analysis should include impacts on energy production and usage, energy shortages, energy costs, including fuel costs and retail electricity prices, and energy employment should be determined. Changes in the energy mix in the United States should be shown over time, including electric capacity additions and reductions by fuel type. Employment and energy cost impacts should be estimated for each energy sector.

Competitiveness. This part of the analysis should include impacts on industrial and manufacturing production and competitiveness. EPA should determine the impacts of regulation on cost of production and employment in the relevant sectors, and the extent to which production and jobs will be reduced as a result of higher costs and foreign competition.

Study design. Scenarios should be constructed for a business-as-usual case (without adoption of the contemplated regulations) and a case where EPA adopts the contemplated regulations. Additional scenarios may be included to test the findings under different appropriate assumptions. Where EPA regulation does not directly regulate but instead requires states to adopt regulations meeting EPA standards (for instance, EPA regulation under the NAAQS program and NSR/PSD program), EPA should estimate state regulatory responses, using a range if necessary. All assumptions, analytical methods and underlying data (or appropriate citations to data sources) should be provided. All impacts should be broken down on a state-by-state basis. Regulations included in the study should not be limited to just those listed in NMA's comments but should include any other EPA regulations that EPA believes will affect the nation's economy, production and usage of energy and manufacturing.

Response: See section 7.2 of the Regulatory Impacts Analysis (RIA) for discussion of cumulative impacts.

Commenter Name: Michael A. Livermore
Commenter Affiliation: Institute for Policy Integrity, New York University School of Law
Document Control Number: EPA-HQ-OAR-2002-0058-2720.1
Comment Excerpt Number: 3

Comment: II. EPA Should Set Emissions Standards that Maximize Net Social Benefits

Given the mandate from Executive Order 12,866, EPA's default practice should be to design regulations that maximize net social welfare, unless directly forbidden by statute. Since Section 112(d)(2) cannot be read to prohibit such a goal, the agency should pursue any beyond-the-floor regulations where benefits justify the costs. This interpretation is not forbidden by the D.C. Circuit opinion in Sierra Club v. EPA (2004), and EPA's regulatory impact analysis indicates that, particularly for the Major Source Proposal, more stringent emission standards than those currently proposed would increase social welfare.

Response: See section 7.2 of the Regulatory Impacts Analysis (RIA) for discussion of cumulative impacts.

Commenter Name: Michael A. Livermore
Commenter Affiliation: Institute for Policy Integrity, New York University School of Law
Document Control Number: EPA-HQ-OAR-2002-0058-2720.1

Comment Excerpt Number: 5

Comment: Administration Policy Requires EPA to Pursue Welfare-Maximizing Regulations

Given the rationales for public regulation of private entities and the directives of Executive Order 12,866, EPA should interpret Section 112(d) to allow the agency to set all emissions standards that maximize net social welfare.

Typically, entities will not voluntarily reduce their own HAP emissions because they do not pay the full costs of those emissions. Air pollution is a classic "negative externality": the harmful effects of pollution are mostly felt by members of the public who cannot directly influence the production of that pollution. Basic micro-economics holds that when an entity does not pay for an effect it
produces, its optimal behavior will not take that effect into consideration. In the status quo, major and area sources of HAP do not pay for the full effect of their emissions. [Footnote: Some entities that will be regulated under the rule may currently pay for emissions which are correlated with the emission of HAP (e.g., sulfur dioxide). While this may encourage some reductions in HAP, it will not necessarily lead to the optimal amount of reductions.] Because there are positive costs (both health effects and environmental effects) from the emission of HAP and regulated entities are not paying for these costs, these entities are currently "over-producing" HAP emissions.

The existence of a negative externality does not necessarily dictate that all HAP emissions must be eliminated. Rather, society should be willing to pay for any change which produces higher benefits than costs. The costs of regulating HAP emissions will be passed from individual sources to society as a whole in a variety of ways: consumers may face higher prices as the cost of production rises; business owners and investors may lose income as regulated entities lose profits; government entities that operate regulated boilers may have to increase taxes or decrease their expenditures in other areas. A wide variety of benefits will counteract these costs, including decreased mortality from lower particulate matter emissions. If the benefits of the proposed rule are higher than the costs, society as a whole is better off.

The goal of maximizing net benefits is enshrined in administration-wide policy under Executive Order 12,866. The Order directs federal agencies to "assess all costs and benefits of available regulatory alternatives" in deciding how to regulate, and then "select those approaches that maximize net benefits unless a statute requires another regulatory approach." [Footnote: Exec. Order No. 12,866 §1, 58 Fed. Reg. 51,735 (1993).] Since, as demonstrate above, EPA has statutory authority to consider net benefits under Section 112(d), the directives of Executive Order 12,866 apply.

Response: See section 7.2 of the Regulatory Impacts Analysis (RIA) for discussion of cumulative impacts.

Executive Order 13175, Consultation and Coordination with Indian Tribal Governments

Commenter Name: Ben Brandes
Commenter Affiliation: National Mining Association
Document Control Number: EPA-HQ-OAR-2002-0058-2787.1
Comment Excerpt Number: 2

Comment: EPA‘s regulatory agenda for the power sector will almost certainly significantly reduce the use of coal for electric generation. While EPA so far has not done any study of the cumulative impact of these regulations on coal use (or otherwise), the contractor EPA uses to model impacts of individual regulations recently produced its own analysis showing that just the EGU MACT standards alone will force major retirements of coal-fueled power plants. [Footnote: Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone, 75 Fed. Reg. 45,210, 45,227/3 (August 2, 2010), quoting the EPA Administrator‘s January 12, 2010 outline of the Agency‘s seven priorities.] Forced retirements will have substantial negative economic impacts nationally, but will also have severe impacts locally, as exemplified by the Arizona Hopi and the Navajo Generation Station:

“Scott Canty, the Hopi Nation‘s general counsel, explained to a panel of lawmakers on Nov. 2 that closure of the Navajo Generating Station would cripple the tribal government. The Hopi Nation relies heavily on coal revenues to fund its government, Canty said. About 88 percent of the tribal government‘s budget comes from revenue generated by coal-fired energy production at the Navajo Generating Station, Canty said. . . . The EPA has proposed rules that would require the power plant to install expensive emissions equipment to address visibility impairment issues at the Grand Canyon. But the plant‘s owners and the tribes argue that the retrofit is too costly.” [Footnote: Luige del Puerto, Hopi Nation in Arizona appeals for help as coal plant face disclosure, ARIZ. CAP. TIMES, Nov. 3, 2009, available at http://www.allbusiness.com/government/government-bodies-officesregional/13389633-1.html.]

Response: EPA is only aware of a couple of instances as provided by the commenter of ICI boilers on tribal lands. The effect of this final rule on communities of tribal governments would not be unique or disproportionate to the effect on other non-tribal communities. To the extent possible, and as discussed in the preamble we have made several changes to reduce the burden of the final rule.

Executive Order 13045, Protection of Children from Environmental Health Risks and Safety Risks

Commenter Name: Los Angeles Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1778
Comment Excerpt Number: 95

Comment: These units also spread mercury and lead, hazardous metals that can harm children's brain, hurting their IQ, limiting their memory and their ability to learn.

Response: Exposure to methylmercury is associated with substantial public health effects. For more information on the health effects associated with mercury, please consult http://www.epa.gov/mercury

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Commenter Name: Margaret Sheehan
Commenter Affiliation: Energy Justice Network
Document Control Number: EPA-HQ-OAR-2002-0058-1884.1
Comment Excerpt Number: 3

Comment: Some of these new biomass boilers will be in urban or other highly populated areas, such as in Madison, Wisconsin. [See reference 3 provided by commenter] Biomass emissions, such as mercury, pose a high health risk to local populations, particularly the most vulnerable, including the youth, the infirm, and the elderly.

Mercury negatively impacts humans and wildlife. EPA analyses conducted for the Mercury Study Report [See reference 4 provided by commenter] to Congress indicate that, for fetuses, infants, and children, the primary health effect of methylmercury is impaired neurological development.

Response: Exposure to methylmercury is associated with substantial public health effects. For more information on the health effects associated with mercury, please consult http://www.epa.gov/mercury

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Commenter Name: Rachel Smolker
Commenter Affiliation: Biofuelwatch
Document Control Number: EPA-HQ-OAR-2002-0058-2805.1
Comment Excerpt Number: 5

Comment: Burning biomass with unknown mercury concentrations poses a high health risk to local populations, particularly the most vulnerable, including the youth, the infirm, and the elderly.

Response: Exposure to methylmercury is associated with substantial public health effects. For more information on the health effects associated with mercury, please consult http://www.epa.gov/mercury

Unfunded Mandates Reform Act of 1995

Commenter Name: Theresa Pugh
Commenter Affiliation: American Public Power Association (APPA)
Document Control Number: EPA-HQ-OAR-2002-0058-0846.1
Comment Excerpt Number: 3

Comment: All APPA members are covered under the Unfunded Mandates Reform Act (UMRA) as they are entities of state or local governments.

Response: See the preamble for a summary of the Unfunded Mandates Reform Act Analysis for the Proposed Industrial Boilers and Process Heaters NESHAP.

Commenter Name: Michael J. Nasi
Commenter Affiliation: Gulf Coast Lignite Coalition
Document Control Number: EPA-HQ-OAR-2002-0058-2800.1
Comment Excerpt Number: 1

Comment: The UMRA cost-benefit analysis fails to factor in the disproportionate economic impact on coal-fired units.

The Unfunded Mandates Reform Act (UMRA) of 1995 requires a cost-benefit analysis. [Footnote: National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters, 75 Fed. Reg. 32006, 32043 (June 4, 2010) (to be codified at 40 C.F.R. pt. 63.] In itsanalysis,the EPA examines future compliance costs and an disproportionate budgetary effects on the proposed rule on any particular areas of the country, State or local governments, types of communities (e.g., urban, rural) or particular industry segments." [Footnote: National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters, 75 Fed. Reg. 32044 (June 4, 2010) (to be codified at 40 C.F.R. pt. 63.]

GCLC respectfully disagrees with the EPA's assessment, The proposed MACT floors could in fact create a disproportionate budgetary effect on different areas of the country, types of communities. and particularly industry segments.

EPA is proposing different MACT floors for boilers based on the type of fuel that is fired. While some fuel sources are being allowed to rely solely upon work practice standards, coal-fired units, for example. will he required to install emission controls and monitoring equipment ranging from activated carbon injection, wet scrubbers, and other emission controls to continuous emissions monitor (CEMs) for opacity, and for larger units, particulate matter (PM). These emission controls and monitoring devices will be costly to obtain, install. and maintain; include costs associated with training, monitoring, and reporting of the emissions; and potentially conflict with other pollution reduction goals (e.g., coal combustion product recycling).

EPA recognizes that it cannot, or should not mandate fuel switching, yet the proposed 'NESI-IAP rules create regulatory burdens based solely on stated policy preference regarding fuel type. GCLC questions how EPA can proceed with the proposed approach without a comprehensive evaluation of whether and to what extent there will be a disproportionate impact on facilities with coal-fired units and those regions that are already dependent upon coal for their energy source.

Response: See the preamble for a summary of the Unfunded Mandates Reform Act Analysis for the Proposed Industrial Boilers and Process Heaters NESHAP.

Regulatory Flexibility Act as Amended by the Small Business Regulatory Enforcement Fairness Act (RFA) of 1996 (SBREFA), 5 U.S.C. 601 et Seq.

Commenter Name: Theresa Pugh
Commenter Affiliation: American Public Power Association (APPA)
Document Control Number: EPA-HQ-OAR-2002-0058-0846.1
Comment Excerpt Number: 2

Comment: More than 90% of public power systems meet the definition and qualify as small businesses under the Small Business Act and the Small Business Regulatory Enforcement and Fairness Act of 1996 (SBREFA).

Response: EPA appreciates the concerns of the regulated small entities. During this rulemaking process we have incorporated several suggestions from the small business panel and we have made several changes in the final rule to reduce the burden on all sources, including small entities. See the Final Regulatory Flexibility Analysis (FRFA) section of the Regulatory Impact Analysis (RIA) which has been prepared for this rule for further discussion of the impact on small entities.

Commenter Name: Los Angeles Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1778
Comment Excerpt Number: 4

Comment: The PTPC mill has upgraded its operations and is in compliance with MACT I and MACT II, along with other federal and state compliance requirements. It's also considered a small pulp and paper company as defined by the Small Business Administration.

The mill has two boilers that are subject to these rules -- a 1976 Stoker-Fired Biomass Boiler and a 1996 Oil-Fired Package Boiler that's used as a backup or auxiliary boiler.
Here are our concerns: PTPC volunteered to be on the SBA committee to review the impact Boiler MACT would have on small businesses. We are dismayed that the recommendations from that work have been, chiefly, ignored.

Response: See response to comment EPA-HQ-OAR-2002-0058-0846.1, excerpt 2 for discussion of impact on small entities.

Commenter Name: Thomas P. Greene, III
Commenter Affiliation: Atlantic Wood Industries, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-1599.1
Comment Excerpt Number: 5

Comment: Most importantly, the wood utility pole and piling industry is made up of many small and family-owned businesses with modest earnings. The cost of required controls would be millions of dollars per boiler at a typical plant like ours which would be unaffordable.

Response: See response to comment EPA-HQ-OAR-2002-0058-0846.1, excerpt 2 for discussion of impact on small entities.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute and National Petrochemical and Refiners Association
Document Control Number: EPA-HQ-OAR-2002-0058-0851.1
Comment Excerpt Number: 10

Comment: Furthermore, as discussed in item 4 below, the details of the work practice requirements in the proposal go beyond those described to the Small Business review panel and the costs and burdens will be much higher than EPA estimated and thus will have a significant impact on small businesses. It is highly likely many small businesses will become non-viable as a result of this rule.

Response: See response to comment EPA-HQ-OAR-2002-0058-0846.1, excerpt 2 for discussion of impact on small entities.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 12

Comment: The small business analysis appears to have been focused on the work practice requirements on the assumption that small businesses only have units that are subject to those requirements. We believe that assumption is false for many situations, because many small businesses have units over 10 MMBTU/hr and units that fire solid, liquid, or gas 2 fuels and thus are subject to emission limitations under this proposal. Given the tremendous costs and questionable feasibility of complying with the proposed emission limits, it is likely many small businesses with such equipment will be unable to make the investments required for compliance and thus will be significantly impacted. There is no relationship between the number of employees in a company (the basis for the small business classification) and the number or type of boilers and process heaters or the emissions from a site that is major for HAP. EPA should re-evaluate the small business impacts.

Response: See response to comment EPA-HQ-OAR-2002-0058-0846.1, excerpt 2 for discussion of impact on small entities.

Commenter Name: Winslow Sargeant
Commenter Affiliation: US Small Business Administration
Document Control Number: EPA-HQ-OAR-2002-0058-2916.1
Comment Excerpt Number: 1

Comment: The proposed rules include some of the recommendations of the SBAR Panel Report, [Significantly, EPA did propose to exempt area sources from Title V permitting requirements and to require yearly boiler tune-ups for gas-fired boilers to improve boiler efficiency in lieu of very expensive emission standards. Advocacy supports these aspects of the proposed rules.] but EPA did not adopt several other key recommendations.

Response: See response to comment EPA-HQ-OAR-2002-0058-0846.1, excerpt 2 for discussion of impact on small entities.

Commenter Name: Eveleen Muehlethaler
Commenter Affiliation: Port Townsend Paper Corp
Document Control Number: EPA-HQ-OAR-2002-0058-2871.1
Comment Excerpt Number: 6

Comment: Attached to the submittal is the March 23, 2009 letter to Administrator Jackson on the Report of the Small Business Advocacy Review Panel for Boiler MACT and CISWI MACT. We would encourage you to review the recommendations from that report as it impacts facilities and small businesses. It encourages health-based compliance alternatives, increased sub-categorizations, reduced monitoring requirements and less frequent reporting.

Response: See response to comment EPA-HQ-OAR-2002-0058-0846.1, excerpt 2 for discussion of impact on small entities.

Commenter Name: Winslow Sargeant
Commenter Affiliation: U.S. Small Business Administration
Document Control Number: EPA-HQ-OAR-2002-0058-2916
Comment Excerpt Number: 7

Comment: The Agency has failed to utilize the discretion under the Clean Air Act to minimize small business burdens while maintaining environmental protection. The current proposal, if implemented without change, is likely to have significant adverse impacts on American jobs and the US economy. Given the importance of this rule to small businesses, we hope to collaborate closely with EPA in formulating the final regulation.

Response: See response to comment EPA-HQ-OAR-2002-0058-0846.1, excerpt 2 for discussion of impact on small entities.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 132

Comment: The small business analysis appears to have been focused on the work practice requirements on the assumption that small businesses only have units that are subject to those requirements. We believe that assumption is inaccurate, because many small businesses have units over 10 MMBTU/hr and units that fire solid, liquid, or Gas 2 fuels and thus are subject to emission limitations under this proposal. Given the tremendous costs and questionable feasibility of complying with the proposed emission limits, it is likely many small businesses with such equipment will be unable to make the investments required for compliance and thus will be significantly impacted. There is no relationship between the number of employees in a company (the basis for the small business classification) and the number or type of boilers and process heaters or the emissions from a site that is major for HAP. EPA should re-evaluate the small business impacts.

Response: See response to comment EPA-HQ-OAR-2002-0058-0846.1, excerpt 2 for discussion of impact on small entities.

Paperwork Reduction Act

Commenter Name: Matthew Todd and David Friedman

Commenter Affiliation: American Petroleum Institute and National Petrochemical and Refiners Association
Document Control Number: EPA-HQ-OAR-2002-0058-0851.1
Comment Excerpt Number: 7

Comment: Overall, we believe the information available to OMB is incomplete and incorrect and the Information Collection Request should be denied and OMB should require new reviews under the PRA and the other regulations applicable to this rulemaking, focusing on the negative impacts of the proposal on jobs and the economy.

Response: EPA has updated its estimates based on a revised inventory, modified testing and monitoring requirements, and considered many commenter suggestions in the revised ICR.

Commenter Name: Matthew Todd and David Friedman
Commenter Affiliation: American Petroleum Institute and National Petrochemical and Refiners Association
Document Control Number: EPA-HQ-OAR-2002-0058-0851.1
Comment Excerpt Number: 11

Comment: The Agency has grossly underestimated the number of controls that will be required and thus underestimated the numbers of continuous monitors and other records and reports that will be required. Thus, they have failed to include all of the recordkeeping and reporting associated with controls that will be required for Gas 2 (and Gas-1fired units under the alternate proposal) and for liquid fired units.

The analysis has failed to include all of the burdens, recordkeeping and reporting associated with the QA/QC of parameter and emissions monitors. An effort appears to have been made to include the initial effort associated with developing a monitoring QA/QC plan, but there does not appear to have been any upkeep estimate for that plan or incorporation of the extensive on-going burdens associated with the requirements specified in proposed §63.7525 for all compliance monitors. This is particularly important for CEMS, because the burdens associated with quarterly audits and annual certifications are very extensive.

The burden analysis does not appear to include annual performance tests for all units subject to emission limits. While there is some provision for fuel testing and performance test skip periods for some pollutants in the proposal, it requires annual performance testing for dioxins/furans (D/F) for all units subject to D/F limits. Since most of the cost and burden of a performance test is associated with performance test setup and measurement of stack gas properties, there is little cost or burden difference between tests for D/F and tests for all of the regulated pollutants.

The burden estimate fails to address the large effort that will be associated with permitting all of these changes and performing the New Source Review analyses required because of the increases in criteria pollutants that will result from this proposal.

The burden estimate incorporates a small amount of time for an initial reading of the regulation, but provides for no ongoing training or for the massive effort associated with incorporating these new requirements into site compliance programs and permits, both initially, and as new boilers and process heaters are added.

Response: The ICR computes the burden for the first three years after the rule is signed. Since existing facilities have three years to comply with the rule, upkeep of the monitoring plan is not included in this ICR. Costs associated with audits and certifications of CEMS are already included in the annual costs line of the burden estimate tables for the different monitoring equipment; RATA costs are calculated using data from U.S. EPA CEMS Cost Model (version 3/07/2007). For each unit with emission limits, annual performance test costs are included in year 3 for those units which performed their initial testing in year 2. EPA agrees that training hours are necessary and has incorporated this into the revised burden estimates.
Changes in burden estimates for the New Source Review program are covered under a separate ICR, "Prevention of Significant Deterioration and Non-Attainment New Source Review (Final Rule for Flexible Air Permits) OMB Control Number 2060-0003. After the final boiler rule is published, the next revision of the Flexible Air Permits ICR will adjust its estimates for NSR burden and costs. Please see the preamble for a response on how EPA estimated the number of units expected to install controls.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 13

Comment: The burden estimate incorporates a small amount of time for an initial reading of the regulation, but provides for no ongoing training or for the massive effort associated with incorporating the new requirements into site compliance programs and permits, both initially and as new boilers and process heaters are added. EPA should add this cost to its burden estimates.

Response: See response to comment EPA-HQ-OAR-2002-0058-0851.1 excerpt 11 for how we incorporated training costs and considered permitting burden.

Commenter Name: James P. Brooks
Commenter Affiliation: Maine Department of Environmental Protection, Bureau of Air Quality
Document Control Number: EPA-HQ-OAR-2002-0058-2746.1
Comment Excerpt Number: 16

Comment: The Maine DEP also respectfully requests that EPA provide additional Section 105 funding to states for implementation of the Area and Major Source Boiler MACTs. These rules will affect an enormous population of boilers nationwide, will result in the need for thousands of permit amendments, and will put a tremendous strain on already stretched state resources.

Response: The EPA appreciates the concerns related to the burden on state agencies. Providing additional funding under Section 105 of the Clean Air Act is an important consideration but outside the scope of this particular rulemaking. The Agency has revised testing frequencies and other compliance and permitting provisions in the rule to reduce the burden on states.

Commenter Name: Randall D. Quintrell
Commenter Affiliation: Georgia Paper and Forest Products Association, GPFPA
Document Control Number: EPA-HQ-OAR-2002-0058-2905
Comment Excerpt Number: 16

Comment: EPA's supporting rationale in the preamble that the extensive testing under the proposed Boiler MACT requirements would improve their database is hardly justification for this unreasonable testing burden, even if it could generate valid data. The Boiler MACT should not be used as a tool for EPA to collect data at the expense of the regulated community. The excessive testing burdens in the Rule appear to us to be just that. If EPA legitimately believes it needs more data, then it must follow the protocols of the Paperwork Reduction Act (PRA), submit a formal Information Collection Request (ICR) and justify the cost.

Response: See Preamble for a discussion of modifications made to reduce testing and monitoring burden on affected entities.

Commenter Name: Jim Eubank
Commenter Affiliation: Kentucky Division of Air Quality
Document Control Number: EPA-HQ-OAR-2002-0058-3176.2
Comment Excerpt Number: 22

Comment: There will be a substantial increase in the number of compliance tests and CEMS certification tests. The Division currently has 4 positions available for reviewing test protocols, observing the tests and reviewing test reports. The Division's workload is going to increase and current budget constraints simply mean that the agency will not be able to witness all tests.

Response: See the preamble for response to how EPA modified CO limits and compliance mechanisms, which reduce the number of required RATAs.

Commenter Name: Jim Eubank
Commenter Affiliation: Kentucky Division of Air Quality
Document Control Number: EPA-HQ-OAR-2002-0058-3176.2
Comment Excerpt Number: 23

Comment: New or existing boilers and process heaters are required to conduct initial and annual performance tests. The increase in compliance tests will impact the state financially. The state currently spends approximately 3 business days per compliance test observation, per source. The work load includes reviewing compliance test protocols, observing the test, and reviewing the final test report. EPA estimates there are currently 13,555 boilers and process heaters at major sources.

Response: See the preamble for response to how EPA modified CO limits and compliance mechanisms, which reduce the number of required RATAs.

Commenter Name: Jim Eubank
Commenter Affiliation: Kentucky Division of Air Quality
Document Control Number: EPA-HQ-OAR-2002-0058-3176.2
Comment Excerpt Number: 25

Comment: The proposed regulation requires the use of CO CEMS. The CO CEMS will be required to be certified through RATAs and audits. State, local, and tribal agencies review and observe the quarterly RATAs. This will increase the work load for agencies and current funding sources do not provide adequate funds to meet the new demands.

Response: See the preamble for response to how EPA modified CO limits and compliance mechanisms, which reduce the number of required RATAs.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 133

Comment: The burden estimate incorporates a small amount of time for an initial reading of the regulation, but provides for no ongoing training or for the massive effort associated with incorporating the new requirements into site compliance programs and permits, both initially and as new boilers and process heaters are added. EPA should add this cost to its burden estimate.

Response: See response to comment EPA-HQ-OAR-2002-0058-0851.1 excerpt 11 for how we incorporated training costs and considered permitting burden.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 134

Comment: EPA has not included the cost of the ongoing energy management program in its burden estimates. This proposed requirement for an energy management program expands a one-time initial energy audit requirement to an ongoing effort that adds continuing personnel, monitoring and recordkeeping requirements. EPA should add this cost to its burden estimates.

Response: The ICR computes the burden for the first three years after the rule is signed. Since existing facilities have three years to comply with the rule requirements the ongoing energy management program is not included in this initial ICR, but will be incorporated in future ICR renewals for this rule.

Executive Order 12898: Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations

Commenter Name: Los Angeles Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1778
Comment Excerpt Number: 93

Comment: [Question from panelist] you mentioned a cumulative impact analysis. Do you have information available as to how that's being carried out?
MS. BABICH: I think that if you look at the California EPA process that's going on they have a Cumulative Impacts Precautionary Approaches Work Group that we fly up to Sacramento to be a part of. And what they've just finished wrapping up, along with some assistance from the University of Berkeley and Dr. Amy Kyle, is really looking at the data gaps that are out there. And I don't necessarily mean that we need to spend 40 years collecting more data. We obviously need to move forward on the data we have. But they have a very good process and she's a very commendable toxicologist who can actually give us an honest opinion.
That's what we're looking for. We don't need to fudge it one way or the another. But let's really look at where we are and see where these data gaps are so that we can make better informed decisions. So I would say that you might want to plug into that or Dr. Joe Lew (phonetic) from the California Environmental Rights Alliance who couldn't be with us here today. He has been working as a representative of E.J. communities on that panel and I'm sure that he could give you information in a way that would be easier for you to process than I can probably do at this time.

Response: The cumulative risk sources listed by the commenter have been noted. We appreciate the information and agree that closing the data gaps will better inform regulatory decisions. Risk issues will be addressed during the residual risk review phase, including any consideration of cumulative risks of HAP.

Commenter Name: Houston Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1876
Comment Excerpt Number: 21

Comment: There has been a lot of talk over the past couple of years from EPA about protecting environmental justice communities ensuring that environmental justice is a part of the decision-making process of everything that EPA takes on. I think that this is a clear example where better protecting and better serving environmental justice communities would be better served by a stricter interpretation of what is a solid waste; as well, using carbon monoxide as a surrogate for other sorts of VOCs, especially those which we struggle so mildly with in the Houston area. I don't think that, again, is going to serve environmental justice communities well.

Response: As the commenter notes, this rule and the definition of solid waste are interconnected. EPA recently tightened its definition of solid waste in a rule that clarifies which non-hazardous secondary materials are considered solid waste. The major source rule for boilers establish limits for CO. By imposing emission limits on carbon monoxide, EPA expects to reduce emissions of formaldehyde, acetaldehyde, and polycyclic aromatic hydrocarbons. Further discussion on this issue is found in responses to comments related to the use of CO as a surrogate for organic HAP.

Commenter Name: Houston Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1876
Comment Excerpt Number: 24

Comment: MR. THOMAS: How are you defining "environmental justice communities"? You have to -- I know it's a very complicated issue.
MR. TEJADA: Yeah, the EPA doesn't even really have a good definition of environmental justice communities, and I think that's one of the things that NEJAC is -- is struggling with, as well, finding exactly what it means to take environmental justice and give it its full measure in the decision-making process, exactly where that comes into the decision-making process, exactly who are environmental justice communities. That's one of the things that I think that is most challenging about Houston, is that it's not just the usual suspects. I think most of the ten-point communities of major industry in the Houston area are obviously environmental justice communities following the regular interpretations of low socioeconomic levels, the racial profile of the community, its proximity to major sources, is a good start.

But especially in Houston, one of the
things that my organization has been struggling with a lot over the past year is that we are finding small, yet major sources of pollution buried within our entire community from unusual suspects, such as automotive mechanics, things such as metal fabrication or foundries.

So I think these sorts of rules that deal
very specifically and are very well defined in things such as a boiler versus an incinerator or solid waste, especially in the Houston region, which I think even by a narrow definition of environmental justice community would probably have more EJ communities than anywhere else in the United States; that is further multiplied when you look at Houston itself being the largest city without any form of zoning in the United States.

If you actually pull back the cover of
Houston, you start to find many communities sprinkled throughout the entire region that face very specific, but very serious threats from air emissions. We're dealing with one about a half mile from downtown right now. A historic black community that has a boundary in the center of the community, and that boundary from its permit, which was only taken out a few years ago, its historic operational practices, the emissions and locations of the different units within the facility that, that community has been very poorly served by a poor regulatory definition of how a boundary of that size should operate.

And this rule or these rules are exactly
the sort that need to be very specific and very well defined in order to better protect exactly those sorts of communities that don't have the profile of Manchester or Galena Park or Baytown.

Response: While the Agency does not have a standard definition of EJ communities, within the context of this rule EPA expects that minority and low income communities will likely experience positive impacts (e.g., reduced incidence of adverse health effects). The demographic data for the Census blocks near these facilities[1] suggest that low-income and minority populations are higher than the national average in these areas in proportional terms. The commenter also points out that EJ communities face serious impacts from air pollution sources, which may vary from community to community, such as the foundry mentioned by the commenter. While the comment on foundries is beyond the scope of the boiler rule, EPA agrees on the importance of well-constructed, specific regulations to limit emissions from specific source categories such as foundries.

Commenter Name: Los Angeles Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1778
Comment Excerpt Number: 77

Comment: EPA also failed to include
an assessment of individual hot spot EJ communities.
Wilmington is one of those communities that should have
been looked at more thoroughly to identify what the
standard in an appropriate measure to protect a hot spot
EJ community, and we ask that you do that.

Response: EPA's current environmental justice approach is a proximity based analysis that compares aggregate populations in close proximity to the regulated source to national averages. We do acknowledge that examining 'hot spots' may provide additional information about local impacts that could be relevant to local or regional efforts to reduce risk as well as to national rulemakings.

Commenter Name: Los Angeles Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1778
Comment Excerpt Number: 81

Comment: Your definition of a major source
is not acceptable. Environmental justice communities
want the same air quality standard for all facility
boiler air pollution sources.

Response: We recognize that from the community perspective any source that has the potential to adversely impact the community is a "major" source. However, for the purpose of our rule making, EPA is bound by law to the definition of a major source set forth in the Clean Air Act Amendments Sec. 112 (a) (10 (1). That definition states that a ''major source'' means any stationary source (or group of stationary sources) located within a contiguous area and under common control that emits or has the potential to emit considering controls, in the aggregate, 10 tons per year or more of any hazardous air pollutant or 25 tons per year or more of any combination of hazardous air pollutants.

Commenter Name: Los Angeles Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1778
Comment Excerpt Number: 86

Comment: Your definition of the main source of ten tons is not acceptable in my EJ community because we have many toxic sources and no pollution is acceptable when you (inaudible) to toxic source.

Response: We recognize that from the community perspective any source that has the potential to adversely impact the community is a "major" source. However, for the purpose of our rule making, EPA is bound by law to the definition of a major source set forth in the Clean Air Act Amendments Sec. 112 (a) (10 (1). That definition states that a ''major source'' means any stationary source (or group of stationary sources) located within a contiguous area and under common control that emits or has the potential to emit considering controls, in the aggregate, 10 tons per year or more of any hazardous air pollutant or 25 tons per year or more of any combination of hazardous air pollutants.)

Commenter Name: Los Angeles Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1778
Comment Excerpt Number: 96

Comment: Because these devices are so numerous and widespread, their toxic pollution infiltrates communities across the nation. They're harm settles heaviest on those who live near them, communities that are often poorer, less well-educated and minorities. Study after study finds that pollution harms these folks far more than it does others.

Response: The units controlled by this rule are numerous and wide spread. However, "nearness" to one of these sources is not an iron-clad indicator of the extent of exposure or "harm." Emissions models indicate that the concentrations of pollutants are highest in the vicinity of the release point. However, the pollutant concentration (and potential for exposure) steadily decreases as one moves further from the emission's source. But the decrease is not uniform around the source. Lots of things can affect the pollutant path and the rate of dilution. For example predominate wind speed and direction play a major role in determining who experiences the effects. Therefore, it's possible for a community to be adjacent to a source yet experience less exposure than a community further away but in the path of the prevailing wind. Having said that, we believe that the controls placed on these combustion units by this rule will substantially reduce emissions and will provide positive benefits to all those communities previously impacted by the emissions from this source category.

Commenter Name: Los Angeles Public Hearing Transcript

Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1778
Comment Excerpt Number: 105

Comment: We have some substantial concerns over aspects of these proposed regulations.
These industrial sources of pollution are ubiquitous throughout the Los Angeles region and, in many cases, are located in low income areas and communities of color. For instance, of the roughly one dozen refineries in our area, most of which are associated with very high health risks, all but one are located in communities of color. Many of these facilities are poorly using boilers that are decades old and contribute to a lot of pollution, both locally and regionally.

Response: As previously indicated, we believe that the controls placed on these combustion units by this rule will substantially reduce emissions and will result in positive benefits to all those communities previously impacted by the emissions from this source category.

Commenter Name: Houston Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1876
Comment Excerpt Number: 129

Comment: Their harm settles heaviest on those who live near them, communities often that are poor, less educated and populated by minorities. Study after study confirms that it can harm these individuals far more than it does others.

Response: As previously indicated "nearness" to a source is not necessarily an indicator of greater "harm." However, we believe that the controls placed on these combustion units by this rule will substantially reduce emissions and will result in positive benefits to all those communities previously impacted by this source category. EPA expects that those who live nearest to sources that are impacted by this rule will benefit the most from the rule.

Commenter Name: Houston Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1876

Comment Excerpt Number: 154

Comment: There is study going on in Corpus Christi concerning benzine releases from current existing refineries in the area.
This is conducted by a local group called the Citizens for Environmental Justice, conducted after ten years of refusal to bond the Texas commissioner on environmental quality to conduct such a study. That
year-end study determined there were absorbantly high
benzine levels in people living in the Hillcrest
community immediately adjacent to several refineries in
the northern part of Corpus Christi.
In Addition to that, as we determine now,
as a consequence of that study, that hundreds of
millions of dollars worth of hydrocarbons are in the
ground and the groundwater beneath the Hillcrest
neighborhood currently right now seeping into people's
homes and into their bloodstreams. We would urge that
the EPA -- TCEQ, as well, and specifically the EPA move
toward a more cumulative study of emissions -- to look
at the emissions not just at any one plant, but of all
those in the immediate vicinity, whether it be looking
at SO2 or mercury or lead or particulate matter or what
have you.

Response: EPA agrees that cumulative air emission studies will better inform rulemaking.

Commenter Name: Arlington Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1779
Comment Excerpt Number: 69

Comment: Many of the other toxic pollutants spewing from these sources cause cancer, including formaldehyde, dioxin, cadmium, furans, and hydrochloric acid. Because these devices are so numerous and so widespread, their toxic pollution infiltrates communities across the nation. Their harm to health settles heaviest on those who live near them, communities that are often poorer, less well educated, and minorities.

Study after study finds that pollution harms these folks far more than it does others.

Response: As previously indicated "nearness" to a source is not necessarily an indicator of greater "harm." However, we believe that the controls placed on these combustion units by this rule will substantially reduce emissions and will result in positive benefits to all those communities previously impacted by this source. To the extent that greatest impacts are associated with “nearness” to the source, then those living nearest to the source are anticipated to benefit the most from this rule.

Commenter Name: Arlington Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1779
Comment Excerpt Number: 112

Comment: How is EPA evaluating the environmental justice impacts of these rules? In the documents that were provided for the webinar that the Agency conducted last Wednesday -- the rather excellent webinar I might add -– in those documents it described the demographic evaluation of population distribution around the sources impacted by the Boiler MACT CISWI rule and the definition of non-solid hazardous waste.

EPA’s demographic analysis of the industrial boilers rule clearly shows that 33 percent of the population around these existing facilities are people of color, and 29 percent of the population around the CISWI incinerators are people of color. Both analyses demonstrate that areas in closest proximity to these two categories of facilities exceed the percentage of people of color in the nation’s population at large, which is 25 percent.

I want to note that while the demographic analysis represents a significant step forward by EPA in determining the potential impacts of its rulemaking, it is nonetheless an insufficient analysis of adverse impact of the operations of these facilities on the nearby communities.

The demographic analysis also shows that surrounding communities also have higher levels of people living at or below the national poverty levels. EPA’s determination of benefits of these rules to environmental justice communities outweighing impacts is spotty and needs to be expanded to include public health impacts that extend beyond the simple and mere demographic analysis.
[Question from Panelist]In your written comments, the more detailed comments, will you be providing any input to us on how we should factor in the economic impacts to environmental justice, the job losses, plant closures that would take away health insurance and things on how we should account for that?

MS. MILLER-TRAVIS: I wasn’t planning to, but I can now that you’ve asked that question; but let me say this: It is a fairly strong misnomer to believe that or to assume that because a facility is –-

MR. WAYLAND: True.

MS. MILLER-TRAVIS: -- operating in a particular demographic or geographic location that the people who live in closest proximity to that facility necessarily work in that facility or nave any economic benefits. That’s a widely held misunderstanding. And just because a facility is in a location doesn’t mean that the people who live closest to it work in that location and have some economic benefits.

So –- but your question is nevertheless a valid one, and I will try and address it in my written comments.

Response: The development of EJ analysis and its application to rule making is relatively new to EPA. The primary focus to date has been on determining the demographic makeup of those populations in the vicinity of a source and, therefore, potentially affected by a specific rule making. Over time, we expect to improve our methodology for measuring health impacts and the economic impacts mentioned by commenters. The development of a comprehensive Agency-wide technical guidance on how to do an EJ analysis is currently underway. This guidance will contain a major economics component and is anticipated to address economic questions such as those raised here.

Commenter Name: Arlington Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1779
Comment Excerpt Number: 132

Comment: I really wanted to talk a little bit more about the stories of communities that I've been in in terms of there are all kinds of things that are thrown in boilers that are small, medium-sized, large, and essentially exempting facilities across this country from having to install protective controls on those facilities, has continued to put those communities at risk.

Response: The boiler rules adopted by EPA are designed to address the concerns and risks that the commenter mentions. The major source boiler rule will reduce emissions of acid gases, such as hydrogen chloride and hydrogen fluoride, mercury, lead, cadmium, other non-mercury metals, organics, and chlorinated dioxin/furans, while the area source boiler rule will reduce emissions of mercury, non-mercury metals, and organics. This will be the result of emissions limits and work practice standards, which are required for major and area source boilers, respectively.

Commenter Name: Arlington Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1779
Comment Excerpt Number: 136

Comment: The Sierra Club's Environmental Justice and Community Partnership Program, EJCP, has provided support to more than dozens of low income and communities of color in their environmental justice struggles. We work to –- we work with low-income and communities of color to overcome environmental assaults on their lives and communities. The Sierra Club's work is national in scope. We were founded in 1892, and we have about a million members, yet it has a grassroots presence everywhere in the county. It is volunteer based and operated and includes professionals willing to devote their volunteer time to build local communities as well.

We have successfully built such bridges in our EJCP partnerships program in El Paso, Detroit, Flagstaff, Memphis, Minneapolis, New Orleans, Washington, D.C., and the Appalachia region and in Puerto Rico, bringing together Sierra Club volunteers, staff, affected community members to strengthen the fight against environmental injustices.

We want to thank EPA Administrator regarding the Major Source Boilers Rule. We want to thank EPA Administrator Lisa Jackson for taking this step to control the toxic air pollution from chemical plants, refineries, paper mills and other industrial sources that are making our air unsafe to breathe. EPA's new rule will finally make the largest of these facilities control the emissions from their boilers and process heaters. It is really about time. These standards are 10 years overdue. Across the country families and communities need protection these rules will provide.

In addition, once again we appreciate Administrator Jackson's emphasizing environmental justice as one of the main priorities during her tenure. Many environmental justice communities, such as the 48217 Detroit community in which the Sierra Club EJCP program works will greatly benefit from this new rule.

Response: EPA agrees that this rule will have significant benefits to many environmental justice communities.

Commenter Name: Margaret Sheehan
Commenter Affiliation: Energy Justice Network
Document Control Number: EPA-HQ-OAR-2002-0058-1884.1
Comment Excerpt Number: 10

Comment: The EPA should continue to consider the disproportionate impact that incinerators have on poor and minority communities. According to the EPA's webinar on national emission standards for boilers, process heaters and incinerators, [See reference 26 provided by commenter] for populations living near disposal and processing facilities that may receive wastes diverted from incinerators, the results suggest that percentages of low-income and minority populations are slightly higher than national average. These results should not be used to justify avoidance of heightened standards for incinerators because low-income communities are already disproportionately affected by air pollution [See reference 27 provided by commenter]. The pollution from industrial air pollution sources, such as incinerators, accumulates in places where minority populations are disproportionately affected. Id.

The EPA should do more studies to test the background levels of already existing pollution of communities affected by incinerator emissions. Background levels of air pollution in these communities are often higher than in other areas because, in general, low-income neighborhoods experience more of all forms of pollution (including air and water pollution, as well as toxic waste pollution) than do neighborhoods that maintain higher levels of income [See reference 28 provided by commenter].
For example, a biomass incinerator was planned to be built in Springfield, Massachusetts, a city described as already having "an 'F' in air quality" [See reference 29 provided by commenter]. In

fact, Springfield ranks number fourteen on the Asthma and Allergy Foundation of America's ranking of U.S. Metropolitan areas according to prevalence of asthma [See reference 30 provided by commenter]. The EPA should use the results of studies of background emissions to strengthen regulation of emissions; for example, if an inner-city community already has high dioxin emissions, emission standards should be higher [See reference 27 provided by commenter].

Response: We agree with the commenter that the consideration of disproportionate impacts on poor and minority communities is an important priority in rulemaking. We also agree that better background data will improve the rulemaking process for all populations, including minority and low-income populations. In the environmental justice analysis completed for this rulemaking, proximity to a source was used as a surrogate for exposure to air pollutants. EPA also recognizes that the solid waste definition rule is intricately tied to the Boiler rule and that while there may be benefits associated with decreased air emissions from Boilers, there may also be disbenefits associated with diversion of waste for boiler units.

Commenter Name: G. Vinson Hellwig and Robert H. Colby
Commenter Affiliation: National Assocation of Clean Air Agencies
Document Control Number: EPA-HQ-OAR-2002-0058-2841.1
Comment Excerpt Number: 34

Comment: In its discussion of environmental justice issues, EPA asserts that the rule meets environmental justice concerns because it does not increase HAP emissions in minority and low income areas. We suggest that this is too low a test for disparate impact. If this rule reduced HAP emissions broadly across the country, except in minority and low-income areas, a disparate impact might result. Here, it has been established that industrial boilers are often located in minority/low-income communities and that the reductions in HAPs from the proposed rule will in fact disproportionally impact those communities – but in a beneficial way. EPA's preamble should reflect this fact.

Response: The preamble states that because the rule does not allow emission increases, the EPA has determined that the proposed rule will not have disproportionately high and adverse human health or environmental effects on minority, low-income, or Tribal populations. This statement supports EPA's determination that it has complied with the terms of the Executive Order, which by its terms focuses on adverse impacts. The preamble goes on to discuss environmental justice issues more broadly by focusing on the demographic analysis that shows that that major source boilers are located in areas where minorities' share of the population living within a three-mile buffer is higher than the national average. For these same areas, the percent of the population below the poverty line is also higher than the national average. Because of the emissions reductions mandated by the rule, EPA agrees that the beneficial effects from the rule will be larger for the average minority and low income American than for all Americans.

Commenter Name: N/A
Commenter Affiliation: Sierra Club, Clean Air Task Force, Earthjustice, and Natural Resources Defense Council

Document Control Number: EPA-HQ-OAR-2002-0058-3187.1
Comment Excerpt Number: 68

Comment: As EPA reports, its own "demographic analysis showed that major source boilers are located in areas where minorities' share of the population living within a 3-mile buffer is higher than the national average. For these same areas, the percent of the population below the poverty line is also higher than the national average." 75 Fed. Reg. 32,048 (citing U.S. EPA, Preliminary Review of Environmental Justice Impacts (April 2010) (EPA-HQ- OAR-2002-0058-0835]).

We encourage the Agency to continue to collect facility-based emissions information, including related to high-emitting boilers as well as short-term assessments of peak emissions during abnormal operating conditions, and in areas where many industrial boilers and other HAP emissions points are located. These should be followed up with dispersion modeling to better understand human exposure at the site of the closest individual (fence-line). Information gathering and better understanding the cumulative health impacts in areas where many sources of HAP are located together (for example, near refineries) would be beneficial.

Response: EPA agrees that in some cases dispersion modeling is an appropriate component in environmental justice analytical work. The environmental justice analytical process is undergoing continual development and refinement. In future rulemakings we expect that dispersion modeling will be used when appropriate from a rulemaking and resource prospective. EPA agrees that cumulative emission studies will better inform rulemaking.

Commenter Name: Rachel Smolker
Commenter Affiliation: Biofuelwatch
Document Control Number: EPA-HQ-OAR-2002-0058-2805.1
Comment Excerpt Number: 13

Comment: EPA Should Further Study the Effect of Biomass Emissions on Environmental Justice Issues.
The EPA should continue to consider the disproportionate impact that incinerators have on poor and minority communities. According to the EPA's webinar on national emission standards for boilers, process heaters and incinerators, 21 [Environmental Protection Agency. Background on National Emission Standards for Industrial, Commercial, and Institutional Boilers and Process Heaters; and Commercial/Industrial Solid Waste Incinerator (CISWI) Units. (2010). Retrieved from http://www.epa.gov/apti/webinars/20100609combustion.pdf] for populations living near disposal and processing facilities that may receive wastes diverted from incinerators, the results suggest that percentages of low-income and minority populations are slightly higher than national average. These results should not be used to justify avoidance of heightened standards for incinerators because low-income communities are already disproportionately affected by air pollution.22 [Ash, Michael & Boyce, James. (2009). Tracking Toxic Pollution from America's Industries and Companies to our States, Cities and Neighborhoods. Pg. 8. Retrieved from http://college.usc.edu/pere/documents/justice_in_the_air_web.pdf] The pollution from industrial

air pollution sources, such as incinerators, accumulates in places where minority populations are disproportionately affected. Id.

The EPA should do more studies to test the background levels of already existing pollution of communities affected by incinerator emissions. Background levels of air pollution in these communities are often higher than in other areas because, in general, low-income neighborhoods experience more of all forms of pollution (including air and water pollution, as well as toxic waste pollution) than do neighborhoods that maintain higher levels of income. [Morello-Frosch, Rachel. "Discrimination and the Political Economy of Environmental Inequity." Environment and Planning C: Government and Policy . 2002, Vol. 20, pp.477-496]. or example, a biomass incinerator was planned to be built in Springfield, Massachusetts, a city described as already having "an 'F' in air quality." [Mobilization for Climate Justice. (2010). Coaltion of Activists Protest Biomass Incinerators at State Global Warming Hearing in Springfield, Massachusetts. Retrieved from http://www.actforclimatejustice.org/2010/06/coalition-of-activists-protest-biomass-incinerators-at-state-global- warming-hearing-in-springfield-massachusetts/#more-2973]In fact, Springfield ranks number fourteen on the Asthma and Allergy Foundation of America's ranking of U.S. Metropolitan areas according to prevalence of asthma.25 [Human Resources. Business and Legal Resources. (2004). Asthma Group Ranks Worst Metro Areas Retrieved from http://hr.blr.com/newsAlternate.aspx?category=5&topic=66&id=9412] The EPA should use the results of studies of background emissions to strengthen regulation of emissions; for example, if an inner-city community already has high dioxin emissions, emission standards should be higher.

Response: We agree with the commenter that the consideration of disproportionate impacts on poor and minority communities is an important priority in rulemaking. We also agree with the commenter that better background data will improve the rulemaking process for all populations, including minority and low-income populations. In the environmental justice analysis completed for this rulemaking, proximity to a source was used as a surrogate for exposure to air pollutants. EPA also recognizes that the solid waste definition rule is intricately tied to the Boiler rule and that while there may be benefits associated with decreased air emissions from Boilers, there may also be disbenefits associated with diversion of waste for boiler units.

Health Based Compliance Alternatives

HBCA: Appropriateness of HBCA for Mn or HCl

Commenter Name: Houston Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1876
Comment Excerpt Number: 119

Comment: Several options have been proposed for which EPA offered little or no justification and analysis. Some are also of doubtful legality; in particular, the clearly erroneous suggestion that EPA could establish risk-based exemptions at levels less stringent than the MACT floor. NACAA recommends that EPA avoid options that carry a substantial risk of a lawsuit that delays implementation of these important public health protections.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Arlington Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1779
Comment Excerpt Number: 29

Comment: We're also concerned with the exclusion of the health-based compliance alternative of the HCPA from the proposed rule. Section 112(d)(4) of the Clean Air Act establishes a mechanism for EPA to exclude facilities from certain pollution control regulations and circumstances when these facilities can demonstrate that emissions do not pose a health risk.

Using the discretionary authority under Section 112(d)(4), EPA may allow a facility to demonstrate the potential proposed risk of emissions for certain pollutants such as manganese and hydrogen chloride from the facility. If a facility can show that its emissions are below the established thresholds for levels posing a risk of human health, EPA can use these data to exclude from requirement sources from which emissions do not pose a risk.

Using HBCA at the outset would allow facilities to comply based on health-based data rather than taking the interim step of installing emission control technology.

We believe the use of the HBCA as a logical tool and that when a facility can meet a more stringent health-based standard without the necessity of expensive emission control equipment, the HBC should be allowed.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Arlington Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1779
Comment Excerpt Number: 61

Comment: The Clean Air Act offers U.S. EPA discretion in certain areas that can and should be used to help balance economic and environmental interests. Exercising this discretion is particularly important in difficult economic times as regulatory burdens can become the straw that breaks the economic backs of U.S. manufacturers and jeopardizes the jobs that are crucial to sustained economic recovery.

We ask that EPA exercise this Clean Air Act discretion with strength and vision to focus resources on serious health threats from air emissions and offer relief from economic burdens when such health threats are not indicated.

To relieve some of the burden for these boilers and process heaters, EPA should exercise the health threshold discretion that Congress allows under Section 112(d)(4) of the Act. Congress recognized that some pollutants are safe at low concentrations, and they allowed EPA to consider this health threshold when setting emission limits. Hydrogen chloride is a common acid and one of those compounds that is safe at low concentrations. EPA may use health risk information to test emission standards that reflect health thresholds so that we are not spending money on control equipment that is unnecessary required to protect human health.

In these strained economic times, EPA should certainly exercise its discretion to stop the regulatory burden when health is adequately protected. This can reduce environmental expenditures by two t three million dollars per unit at each of our municipal electric plants.

Response: See preamble for response to final decision on Health Based Compliance Alternative. As for economic impacts of the rule, the EPA used a standard market analysis to analyze the proposed MACT standards. The approach uses a single period multimarket partial equilibrium model to compare pre-policy market baselines with expected post-policy market outcomes. The analysis' time horizon is the intermediate run; some production factors are fixed and some are variable and is distinguished from the very short run where all factors are fixed and producers cannot adjust inputs or outputs. The intermediate time horizon allows us to capture important transitory stakeholder outcomes. Key measures in this analysis include industry-level changes in price levels, production and consumption, jobs, international trade, and social costs (changes in producer and consumer surplus). The analysis shows market responses with a very small increase in imports and a small job change.

Commenter Name: Arlington Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1779
Comment Excerpt Number: 118

Comment: EPA has the Clean Air Act authority through the 112(d)(4) to formulate MACT rules using a health threshold approach that would provide flexibility for sources while also ensuring the protection of public health. There is precedent for using that approach, and CIBO urges EPA to include that approach as a means to provide acid gas control in a cost-effective manner.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Don Grimm
Commenter Affiliation: Hood Industries, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2352
Comment Excerpt Number: 1

Comment: EPA should establish health based emissions limitations for acid gases and manganese under § 112(d)(4).
Section 112(d)(4) authorizes EPA to set health-based emissions limitations when establishing standards for HAPs under § 112(d). Section 112(d)(4) is a powerful tool that enables EPA to match the stringency of a HAP emissions limitation to the level determined necessary to fully protect human health. As a result, the standard is no more stringent and no less stringent than needed to get the job done.

The default technology-based method of setting MACT standards is a cookie cutter approach that can and does result in HAP emissions limitations that go well beyond what is needed to protect the public from HAP emissions. The clear purpose of § 112(d)(4) is to prevent this from happening. The legislative history of § 112(d)(4) is abundantly clear on this point. In formulating § 112(d)(4), Congress recognized that, "For some pollutants a MACT emissions limitation may be far more stringent than is necessary to protect public health and the environment." [Footnote: S. Rep. No. 101-128 (1990) at 171]. As a result, § 112(d)(4) was provided as an alternative standard setting mechanism for HAPs "where health thresholds are well-established … and the pollutant presents no risk of other adverse health effects, including cancer…."

When the first Industrial Boiler MACT was promulgated in 2004, it included health based emissions limitations for two HAPs – hydrogen chloride ("HCl") and manganese. These health-based emissions limitations were rigorous standards that demanded accountability. They were a winner for the Agency and the public because public health would have been protected with an ample margin of safety. At the same time these standards were a winner for affected sources because the standards would not have blindly required emissions to be reduced far below the levels needed to assure that the public was protected. It was estimated at the time that these health based standards would have saved over $2 billion in compliance costs, as compared to the technology-based standards that otherwise would have applied.

In the newly proposed Industrial Boiler MACT, EPA acknowledges its authority under § 112(d)(4) to establish a health-based emissions limitation for threshold pollutants in lieu of a MACT emissions limitation. However, the Agency proposes not to establish any health based emissions limitations "[g]iven the limitations of the currently available information (i.e., the HAP mix where boilers are located, and the cumulative health impacts from co-located sources), the environmental effects of HCl, and the significant co-benefits of setting a conventional MACT standard for HCl." Nevertheless, EPA asks for comment on a wide range of issues related to the justification for setting health based emissions limitations and the method by which they should be set.

Ample scientific information supports a determination that HCl, hydrogen fluoride, hydrogen cyanide, and manganese are threshold pollutants and, thus, are eligible to be regulated under § 112(d)(4). In addition, the Agency has the technical tools and significant factual support for establishing health based emissions limitations for these HAPs that would provide the requisite ample margin of safety to health and the environment. Thus, health based emissions limitations are fully justified on scientific and technical grounds. EPA should set health based emission limitations for HAP acid gases and, like in the2004 rule, a health based emissions limit for manganese, which should be implemented in conjunction with a Total Select Metal ("TSM") standard (where the TSM standard would be an alternative to the PM surrogate, and where a "TSM less manganese" option would be provided when a source elects to comply with the health based compliance alternative for manganese).

From a legal standpoint, the statute makes clear that criteria pollutant co-benefits associated with the proposed MACT standards may not be considered in deciding whether to establish § 112(d)(4) health based emissions limitations. Also, EPA has failed to explain why the health based emissions limitations it established in the 2004 Industrial Boiler MACT and the justification provided for those limitations should now be reversed. The preamble to the newly proposed rule sets out a number of questions that might be relevant in deciding whether to establish health based emissions limitations, but merely asking questions is not a sufficient basis for reversing prior determinations adopted through notice and comment rulemaking. Thus, EPA's proposal not to set health based emissions limitations runs counter to the law and is based on an inadequate explanation of why the Agency proposes to depart from its prior approach.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Ashley Peterson
Commenter Affiliation: American Meat Institute
Document Control Number: EPA-HQ-OAR-2002-0058-2382.1
Comment Excerpt Number: 5

Comment: EPA should allow facilities to demonstrate that emissions of certain pollutants do not pose a public health concern. A practical, health oriented standard for threshold pollutants would allow sources to demonstrate their emissions of these compounds pose no adverse risk. The Clean Air Act in §112(d)(4), expressly contemplates the use of such an approach, which can be implemented without sacrificing risk reduction benefits. A health threshold standard is critical to the future viability of biomass and other boiler fuels. EPA has indicated to stakeholders that this alternative will not be part of the proposed rule language. EPA should revisit this thinking and make the health threshold standard an integral part of its proposed Rules and allow an opportunity for public comment on this approach.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: John Williams
Commenter Affiliation: Maine Pulp and Paper Association
Document Control Number: EPA-HQ-OAR-2002-0058-1913.1
Comment Excerpt Number: 9

Comment: Health-Based Compliance Alternative. There needs to be a Health-Based Compliance Alternative (HBCA) for HCl. As proposed, certain of the Maine Mill boilers would be required to install a scrubber to remove small concentrations of HCl to meet the MACT emissions limits even though there is no health issue. This will result in a huge capital cost of millions of dollars per boiler for no health benefit. EPA is authorized to use HBCAs and there is no point in making the HCl standard tighter and more costly to control if there is no health related issue.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Theresa Pugh
Commenter Affiliation: American Public Power Association
Document Control Number: EPA-HQ-OAR-2002-0058-2714.1
Comment Excerpt Number: 3

Comment: APPA also supports health-based emissions limits ("HBELs") as EPA proposed and supported for the Boiler MACT source category under the 2004 Boiler MACT rule. EPA has clear authority to adopt HBELs under section CAA 112(d)(4) for pollutants "for which a health threshold has been established." As EPA previously acknowledged, a threshold below which no adverse effects are observed has been established for both HCl and manganese. In 2004, EPA concluded that health and safety were protected with an ample margin of safety when the concentrations of HCl or manganese at the point of exposure were below the threshold for health effects. These safe concentrations of HCl and Mn can be assured, as was proposed in 2004, when facilities meet designated stack heights and fenceline distances sufficient to keep HCl and Mn below risk thresholds at the point of exposure. EPA has arbitrarily eliminated HBELs from the proposed rule without providing an adequate explanation for its about-face.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Tim Keneally
Commenter Affiliation: KapStone Paper and Packaging Corporation
Document Control Number: EPA-HQ-OAR-2002-0058-2673.1
Comment Excerpt Number: 4

Comment: Ample scientific information supports a determination that HCl, hydrogen fluoride, hydrogen cyanide, and manganese are threshold pollutants and, thus, are eligible to be regulated under § 112(d)(4). KapStone urges EPA reconsider their decision not to include these health-based limitations in the newly proposed Industrial Boiler MACT. EPA should set health based emission limitations for HAP acid gases and, like in the 2004 rule, a health based emissions limit for manganese, which should be implemented in conjunction with a Total Select Metal ("TSM") standard (where the TSM standard would be an alternative to the PM surrogate, and where a "TSM less manganese" option would be provided when a source elects to comply with the health based compliance alternative for manganese).

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Mark Denzler
Commenter Affiliation: Illinois Manufacturers' Association
Document Control Number: EPA-HQ-OAR-2002-0058-2635.1
Comment Excerpt Number: 6

Comment: Use Health Based Compliance Alternatives. The EPA should allow the use of health-based compliance alternatives that is based upon facility specific emissions of which is modeled against reference concentrations provided by EPA using a health index. This alternative would ensure protection of health and the environment and provide a potentially more cost effective solution in some cases.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Joe O'Rourke
Commenter Affiliation: F.H. Stoltze Land and Lumber Co
Document Control Number: EPA-HQ-OAR-2002-0058-2418.1
Comment Excerpt Number: 6

Comment: Secondly, the EPA should exercise its discretion under section 112(d)(4) of the Clean Air Act to set health-based emission limits. Doing so would eliminate the need for additional controls where threshold pollutants are now low enough to be safe. We at Stoltze agree with AF&PA that the EPA should make the health threshold an integral part of its final rule.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: James P. Brooks
Commenter Affiliation: Maine Department of Environmental Protection, Bureau of Air Quality
Document Control Number: EPA-HQ-OAR-2002-0058-2746.1
Comment Excerpt Number: 10

Comment: The Maine DEP understands that EPA's previous attempts to provide health-based compliance alternatives in standards established under Section 112 have been rejected by the courts. We believe, however, that EPA's proposed standards for hydrochloric acid (HCl) exceed the levels necessary to protect public health and will create an unnecessary compliance burden for affected units. We recommend that EPA apply the provisions of Section 112(d)(4) to the extent possible to establish a more appropriate scheme for HCl emission reductions. We would also suggest EPA consider the application of this provision to the regulation of non-mercury metal HAP as an alternative to compliance with the proposed PM standard.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Jack Carter
Commenter Affiliation: Weyerhaeuser Company
Document Control Number: EPA-HQ-OAR-2002-0058-2797.1
Comment Excerpt Number: 12

Comment: Weyerhaeuser urges EPA to reverse its new position and provide health-based compliance alternatives for HCl and for manganese. (We note for manganese this also necessitates that EPA reintroduce a Total Selected Metals limit as an alternative to the PM surrogate limit for HAP metals.) When the original Boiler MACT was promulgated in 2004, it included "Health Based Compliance Alternatives" (HBCA) as emissions limitations for HCl and manganese. Weyerhaeuser found these alternatives would have been a significant cost reduction factor that still met the CAA goals of reducing health and environmental risk. At that time we intended to employ the HBCA for one or both of the target HAPs at about one-third of our then-existing portfolio of mills. As the AWC and AF&PA comments detail, these health-based emissions limitations were rigorous standards that demanded accountability and were a win-win-win, for the EPA and the public because public health would have been protected with an ample margin of safety, and for affected sources because the standards would not have blindly required emissions to be reduced far below the levels needed to assure that the public was protected.

Even though in the preamble to the proposed Boiler MACT EPA acknowledges its authority under CAA §112(d)(4) to establish a health-based emissions limitation for threshold pollutants in lieu of a MACT emissions limitation, the Agency declined to do so. However, EPA asks for comment on issues related to the justification for setting health based emissions limitations and the method by which they should be set. As proposed, we believe the extreme cost burdens the rule will impose on us and on the industrial boiler owners of the Nation, justify that EPA use the available resources in its toolkit to reduce those costs as long as the health objective Congress attached to this technology-based regulation is maintained. We believe that can be done, and refer EPA to the detailed health and technical justifications for HCL and manganese health-based emission limitations in the AWC and AF&PA comments. We strongly urge EPA to use its discretion to put these alternatives in place.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Steven M. Maruszewski
Commenter Affiliation: The Pennsylvania State University
Document Control Number: EPA-HQ-OAR-2002-0058-2729.1
Comment Excerpt Number: 18

Comment: Health Based Compliance Alternative (HBCA) for HCl
The University believes the HBCA to be a reasonable and responsible compliance alternative. The University submitted its HBCA Eligibility Demonstration in September of 2006. That submission required the University to perform additional stack tests and to engage a consulting firm to compile the documentation. That report showed the University to be well below the standard in the look up chart for our stack height and distance to the property line. The University has not seen any
documentation that would discount the validity of this alternative. The University believes that the reasoning for its inclusion in the original publication is sound and has yet to be successfully challenged.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Jack Carter
Commenter Affiliation: Weyerhaeuser Company
Document Control Number: EPA-HQ-OAR-2002-0058-2797.1
Comment Excerpt Number: 27

Comment: EPA could avoid this concern for many facilities by adopting standards that include a health-based emission limitation, as previously discussed. This would reduce the need to install controls to meet limitations for HCl and metals/PM. If EPA does so, many wood products facilities will not face the problem of a new and potentially high volume process wastewater that is difficult to manage and not possible to permit and discharge from the site. For those wood products facilities that cannot take advantage of a health-based emission limitation, however, the technology EPA has assumed would be available to meet HCl and other limits may still in fact be unavailable due to the constraints on wastewater discharges. To remedy the problem at wood products facilities where this occurs, EPA should adopt work practice standards for control of HCl and other pollutants for which a wet control device would be needed, rather than requiring compliance with numerical emission limitations.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1

Comment Excerpt Number: 28

Comment: AF&PA supports the inclusion of risk-based limits for HCl as a means of minimizing investments that would do little in terms of reducing risk from boiler emissions. The submittal includes two charts that (1) industrial liquid and wood fired boilers do not emit significant amounts of HCl [Footnote: EPA's 2005 National Emissions Inventory, http://www.epa.gov/ttn/chief/net/2005inventory.html], and (2) biomass boilers have inherently low HCl emissions and the top performers do not employ HCl control technologies. Given the nation's need to diversify fuel supplies, EPA should encourage use of domestic, renewable, carbon neutral fuels such as wood residuals, rather than create regulatory programs that discourage their use, especially when their use can be demonstrated not to pose a risk to human health and the environment.

Biomass boilers are not large sources of HCl, and top performers do not employ wet scrubbers to control HCl emissions from biomass. As demonstrated in the chart below, 8 of the 13 top performers for Biomass HCl emissions have dry particulate controls. The units with scrubbers are co-firing sulfur containing fuels such as oil and TDF or are burning sulfur containing process gases.

For liquid boiler top performers, the same issues are present. All but one of the boilers in the liquid HCl floor has no control; one boiler burning residual oil has a fabric filter, which provides no HCl control. One boiler in the liquid mercury floor has an ESP, one has a multiclone, and the rest have no HAP emissions controls. Again, the liquid boiler floors for the fuel based HAP are being driven by fuels that have low chloride and mercury contents, not by boilers employing any type of mercury or HCl emissions controls. It does not make sense to require controls on boilers burning a clean liquid fuel such as distillate fuel oil that do not happen to contain the extremely low chloride or mercury contents that the floor boilers do.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: G. Vinson Hellwig and Robert H. Colby
Commenter Affiliation: National Assocation of Clean Air Agencies
Document Control Number: EPA-HQ-OAR-2002-0058-2841.1
Comment Excerpt Number: 37

Comment: EPA has solicited comment on whether the agency should adopt "risk-based" exemptions for manganese and HCl. Section 112(d)(4) of the CAA provides:
With respect to pollutants for which a health threshold has been established, the Administrator may consider such threshold level, with an ample margin of safety, when establishing emission standards under this subsection.

After careful review, NACAA has concluded that these exemptions are not authorized by the CAA and are not in the public interest. The factual predicate for the use of section 112(d)(4) for acid gas HAP and metal HAPs – the establishment of a health threshold for each of these pollutants – has not been met. Congress authorized risk-based standards only “where health thresholds are well-established...and the pollutant presents no risk of other health effects, including cancer, for which no threshold can be established....”[63 S. Rep. No. 228, 101st Cong. 1st Session, (December 20, 1989), reprinted in A Legislative History of the Clean Air Act Amendments of 1990 (Comm. Print 1993), at 8511.]

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: G. Vinson Hellwig and Robert H. Colby
Commenter Affiliation: National Assocation of Clean Air Agencies
Document Control Number: EPA-HQ-OAR-2002-0058-2841.1
Comment Excerpt Number: 39

Comment: On August 6, 2010, EPA adopted a NSPS for Portland Cement plants. In its final rule EPA specifically rejected adoption of risk-based exemptions for HCl and manganese, making many of the points identified above and also relying on the benefits associated with the co-removal of SO2. There are no differences sufficient to warrant a reversal of that decision in this standard. Moreover, EPA has not identified a proposal for an exemption with sufficient specificity to allow for meaningful comment for a final rule. Finally, there is no record sufficient to support such a proposal and insufficient time under the applicable statutory and judicial deadlines to develop such a proposal and rulemaking record.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: N/A
Commenter Affiliation: Sierra Club, Clean Air Task Force, Earthjustice, and Natural Resources Defense Council
Document Control Number: EPA-HQ-OAR-2002-0058-3187.1
Comment Excerpt Number: 56

Comment: EPA may not lawfully invoke Section 112(d)(4) health risk-based alternatives to MACT floor setting for ICIBPH in this rulemaking.

EPA sets numerical MACT floor limits for acid gases (chlorine (Cl2), hydrogen chloride (HCl), hydrogen fluoride (HF), and hydrogen cynanide (HCN)) emitted by industrial, commercial and institutional boilers through limits on HCl as a surrogate for those ‘non-metal inorganic HAPs’. While we have serious concerns with the Agency’s surrogacy decision, as outlined above, commenters do applaud EPA’s decision to set MACT-based standards for acid gases. The Agency also considered, in the alternative, whether to “exercise [its] discretionary authority to establish health-based emission standards under CAA section 112(d)(4) for HCl and each of the other relevant HAP acid gases – Cl2, HF, and HCN”. 75 Fed. Reg. 32,010. EPA specifically asks several questions pertaining to the limits on the exercise of its § 112(d)(4) authority, and seeks comment on that point as well as soliciting further technical information about the health effects of these pollutants. We offer some responses to those questions here. Our responses should not be taken to suggest in any way, however, that we agree EPA is authorized to exercise the very limited authority it has under §112(d)(4) in this rulemaking.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: N/A
Commenter Affiliation: Sierra Club, Clean Air Task Force, Earthjustice, and Natural Resources Defense Council
Document Control Number: EPA-HQ-OAR-2002-0058-3187.1
Comment Excerpt Number: 57

Comment: The Statute Does Not Permit EPA to Establish Standards under § 112(d)(4) for any HAP for which there is no Existing Health Threshold Based on No Observable Adverse Effects

CAA section 112(d)(4) states that "[w]ith respect to pollutants for which a health threshold has been established, the Administrator may consider such threshold level, with an ample margin of safety, when establishing emission standards under this subsection." 42 U.S.C. § 7412(d)(4) (emphasis added). The use of the phrase "has been established," shows that Congress did not intend for this provision to be used by EPA to spend time and resources during the MACT standard-setting exercise to figure out whether a given pollutant might have a health threshold, but may rely on this authority only where an accepted threshold already is in existence. See Brief for Respondent Environmental Protection Agency in National Lime Ass'n v. EPA, (July 14, 2000). That health threshold, at a minimum must be based on the "no observable effects level" for any health endpoint associated with that pollutant. See S. Rep. No. 101-228 at 171 (1990).

Section 112(d)(4) was included in the 1990 ground up revisions to the air toxics requirements of the Clean Air Act. Prior to 1990, the CAA required individual HAP listing and standard setting, based on public health protection with "an ample margin of safety." CAA of 1970 §112(b)(1)(B), P. Law 91-604 (amended in 1990). The 1990 revisions, of course, included a list of HAPs to be regulated and required that EPA set technology-based standards for those HAPs for listed industries. Section 112(d)(4), as finalized, authorized the Agency to "consider" an "established " health threshold [Footnote: In fact, the Senate Report describes the prerequisite as a "well-established" health threshold. See S. Rep. 101-228 at 171.] in setting such standards. By contrast, an earlier draft of the CAAA would have made the authority to set a health-based standard contingent on a finding that a threshold "can be established" [Footnote: 3 1990 Legislative History at 4425.] a forward looking construct that would accommodate investigation and establishment of the threshold as part of the MACT standard setting exercise, in a way that the final enacted language of §112(d)(4) does not.

Moreover, the legislative history requires that any established health threshold that might form the basis for a health-based alternative standard must be based on the " 'no observable [adverse] effects level' (NOAEL) below which human exposure is presumably 'safe'." S. Rep. No. 101-

228 at 171 (1990). As will be shown below, there is no such established health threshold currently for HCl, or for any of the other acid gases (non-metal inorganic HAPs) EPA identifies as emitted by industrial boilers. As a threshold matter, then, section 112(d)(4) authority to set an alternative, health-based standard for HCl is simply not available to the Agency here, because as shown below, there is no established accepted health threshold for HCl, or the other acid gases, as Congress intended that concept to be understood. In particular, as EPA has admitted, the agency does not know whether or not HCl causes cancer. 71 Fed. Reg. 76,542, 76,553 (Dec. 20, 2006) ("The data are inadequate to make a determination as to whether HCl is carcinogenic in either humans or animals, so EPA has not developed an assessment for the carcinogenicity of HCl."). Obviously, if EPA does not even know whether HCl causes cancer, the agency has not identified an established health threshold below which HCl does not cause cancer. For this reason alone, EPA cannot invoke § 112(d)(4) with respect to HCl.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: N/A
Commenter Affiliation: Sierra Club, Clean Air Task Force, Earthjustice, and Natural Resources Defense Council
Document Control Number: EPA-HQ-OAR-2002-0058-3187.1
Comment Excerpt Number: 58

Comment: EPA Is Not Authorized to Set §112(d)(4) Standards Based on A Surrogate Pollutant.

Because EPA must base any §112(d)(4) health based standard on the "no observable adverse effects level, it may not rely on a surrogate in evaluating or setting risk based standards under §112(d)(4). EPA agrees it would not be an appropriate surrogate for a health-based standard. It is well established that when setting §112(d) MACT-based standards, EPA must set standards for each HAP emitted by a category or subcategory of sources. National Lime Ass'n v. EPA, 233 F.3d 625, 633-34 (D.C. Cir. 2000). Similarly, if the Agency invokes §112(d)(4) authority to consider setting a health-based alternative standard, the Agency must conduct that evaluation on a pollutant-specific basis "with respect to pollutants" for which a health threshold is established. [See 75 Fed. Reg. 32,030 at n. 16.]

Even if HCl could reasonably serve as a surrogate for the other acid gases under a technology-based MACT standard (a point which we do not concede), it cannot be a surrogate in health based standard setting. As shown in Table VI-1 below, for HCl, CL2, and HF, the primary health endpoint is respiratory irritation. [See submittal for table VI-1.] For HCN, however, the primary health endpoint is neurological. Indeed, EPA notes that "[t]hese gases (for example HCN) can act on biological organisms in a ifferent manner than HCl, and each of the acid gases affects human health with a different dose-response relationship." Id. It is inappropriate to select one acid gas (HCl) with one health endpoint to serve as a surrogate for another acid gas (HCN) with a different health endpoint.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 92

Comment: In order to provide additional compliance flexibility for sources, AF&PA also recommends EPA includes a health-based total selected metals (TSM) compliance alternative along with the TSM emission limit option. Similar to the approach EPA took in the 2004 Boiler MACT rule, in the health-based TSM compliance alternative option, manganese emissions would not be included in the TSM calculation if facility emissions of manganese were below health-based thresholds established using either a lookup table or site specific modeling and risk analysis. Combustion of biomass fuels results in higher ratio of manganese to TSM than combustion of fossil fuels, and as stated in the section of our comments that addresses health-based emission limits, manganese is a threshold pollutant and appropriate for consideration in a health-based regulatory approach. Increased use of renewable fuels such as woody biomass is part of our national energy and climate policy. Providing this alternate TSM compliance strategy will provide a compliance mechanism that will not disadvantage the use of wood fuel and potentially create the unintended consequence of replacing woody biomass fuel with fossil fuel.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 127

Comment: The default technology-based method of setting MACT standards is a cookie cutter approach that can and does result in HAP emissions limitations that go well beyond what is needed to protect the public from HAP emissions. The clear purpose of § 112(d)(4) is to prevent this from happening. The legislative history of § 112(d)(4) is abundantly clear on this point. In formulating § 112(d)(4), Congress recognized that, "For some pollutants a MACT emissions limitation may be far more stringent than is necessary to protect public health and the environment." S. Rep. No. 101-228 (1990) at 171. As a result, § 112(d)(4) was provided as an alternative standard setting mechanism for HAPs "where health thresholds are well-established … and the pollutant presents no risk of other adverse health effects, including cancer…." Id.

The first Industrial Boiler MACT was overturned by the D.C. Circuit, but on grounds unrelated to the health- based emissions limitations. Notably, in defending the health- based emissions limitations, the Department of Justice concluded that, "Environmental Petitioners' claim that the statute precludes EPA from establishing alternative standards for threshold pollutants (which petitioners mischaracterize as an exemption) is meritless." Final Brief For Respondent United States Environmental Protection Agency, D.C. Cir. Case No. 04-1385 (Dec. 4, 2006) at 53-54

Giving full consideration to the use of health-based standards is particularly important in the wake of the series of decisions from the D.C. Circuit that have progressively limited EPA's discretion to make common-sense decisions when setting MACT standards under § 112. EPA's authority to set health- based standards under § 112(d)(4) is unassailable. For appropriate HAPs and where the relevant facts substantiate its use, EPA can set health-based standards with full confidence that they will survive judicial review.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 128

Comment: The work that EPA performed in support of the HBELs included in the 2004 rule demonstrates that the proposed standards are far more stringent than needed to assure the protection of public health with an ample margin of safety. The costs and burdens on affected sources and the degree of control needed to provide adequate health and environmental protection are both key factors that should be considered by the Agency in deciding whether to adopt HBELs in the Industrial Boiler MACT.

In the proposed rule, EPA completely ignores these factors. The Agency's discussion of HBELs includes no assessment whatsoever of the costs that might be avoided by adopting HBELs for HCl or manganese. As to potential effects on health or environment, EPA simply raises implementation questions and asserts a lack of information to resolve the questions. Such an approach is facially inadequate in light of the extensive policy, scientific, and technical assessment developed in support of the HBELs in the 2004 Industrial Boiler MACT standard.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 135

Comment: A health protective HBEL under CAA 112(d)(4) could take a number of forms. For example, a tiered approach could be developed where a conservative look-up table provides HCl equivalent emission rate thresholds for various source-receptor combinations. If the look-up table is not viable, then site-specific modeling following established U.S. EPA risk assessment guidance could be performed to establish an appropriate HBEL. For example, detailed dispersion modeling using source specific stack parameters and receptor locations could be used to establish appropriate HBELs. Variability in emissions could be addressed by consideration of variability in fuel consumption and fuel content. A robust statistical method could be applied to assure conservatism with a reasonable level of certainty, such as the 95th percentile commonly applied by EPA. Alternatively, limits for HCl and other pollutants established in air permits could be proposed for use in lieu of establishing separate HBELs.

Response: See preamble for response to final decision on Health Based Compliance Alternative. See preamble for discussion of MACT floor methodologies and statistical variability analysis.

Commenter Name: Mary Graham
Commenter Affiliation: Charleston Metro Chamber of Commerce
Document Control Number: EPA-HQ-OAR-2002-0058-2732.1
Comment Excerpt Number: 1

Comment: The Chamber questions the stringent limits when the results from EPA's air toxics at school monitoring program that was conducted at Chicora Elementary School located in North Charleston, South Carolina showed results from HAP pollutants well below the screening values established by EPA. The recent monitoring at the school shows that stringent reductions imposed by the proposed Boiler MACT standard are not necessary to meet health-based compliance concentrations.

The Chamber offers comments and recommendations on the following key areas of the proposed rule.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Randy A. Gerg
Commenter Affiliation: Hexion Specialty Chemicals, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2634.1
Comment Excerpt Number: 2

Comment: EPA should allow facilities to demonstrate that emissions of certain pollutants do not pose a public health concern. A practical health oriented standard for threshold pollutants like hydrogen chloride and manganese would allow sources to demonstrate their emissions of these compounds pose no adverse risk. The Clean Air Act in §112(d) (4), expressly contemplates the use of such an approach which can be implemented without sacrificing risk reduction benefits. A health threshold standard is critical to the future viability of biomass and other boilers. EPA should make the health threshold standard an integral part of its final rule.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Mary Graham
Commenter Affiliation: Charleston Metro Chamber of Commerce
Document Control Number: EPA-HQ-OAR-2002-0058-2732.1
Comment Excerpt Number: 2

Comment: When the first Industrial Boiler MACT was promulgated in 2004, it included health based emissions limitations for two HAPs — hydrogen chloride ("HCI") and manganese. These health-based emissions limitations were rigorous standards that demanded accountability. They were a winner for the Agency and the public because public health would have been protected with an ample margin of safety. At the same time these standards were a winner for affected sources because the standards would not have blindly required emissions to be reduced far below the levels needed to assure that the public was protected. It was estimated at the time that these health based standards would have saved over $2 billion in compliance costs, as compared to the technology-based standards that otherwise would have applied. The Chamber requests EPA reconsider their decision not to include these health-based limitations in the newly proposed Industrial Boiler MACT.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Melvin E. Keener
Commenter Affiliation: Coalition for Responsible Waste Incineration (CRWI)
Document Control Number: EPA-HQ-OAR-2002-0058-2824.1
Comment Excerpt Number: 14

Comment: The Agency has the authority to establish a health-based standard for HCI.

As EPA knows, the Clean Air Act Amendments of 1990 substantially revised the Nation's program to control hazardous air pollutants. In these amendments, Congress split the program into two phases. In the first phase, the Agency requires control commensurate with "the maximum degree of reduction in emissions" being achieved by the best controlled sources. 42 USC 7412(d)(2) and (3). This phase is commonly referred to as the technology-standard phase. See e.g., 1990 Leg. Hist. at 862, 875, 876, 950, 1029, 1062,1079. In the second phase, EPA is to examine the amount of risk that remains to human health and the environment, and impose further controls if necessary to protect human health with an ample margin of safety, and prevent adverse environmental consequences. 42 USC 7412(f).

This shift to an initial technology-based program was not absolute, however. Congress authorized EPA to use a risk-based approach during the technology-based phase where further regulation was not necessary from a risk standpoint. Consequently, EPA is allowed to delist an entire source category or subcategory, if none of the sources in it emit hazardous air pollutants that create a risk greater than 1 in one million excess cancer cases. 42 USC § 7412(c)(9).

Another risk-based component was enacted in § 112(d)(4). 42 USC § 7412(d)(4). Since at least 1997, EPA has recognized that section 112(d)(4) authorized the Agency to set risk-based emission standards in lieu of technology-based standards. As EPA wrote in a Federal Register notice, "Congress provided in section 112(d)(4) that EPA could, at its discretion, develop riSk-based standards for HAP ‘for which a health threshold has been established,’ provided that the standard achieves,an ‘ample margin of safety.’" 62 FR 33625, 33631 (June 20, 1997). [Footnote: EPA then proceeded to use this authority in the first Plywood MACT. See 63 Fed. Reg. 18754, 18765 (April 15, 1998) (Proposed National Emission Standards for Hazardous Air Pollutants; Proposed Standards for Hazardous Air Pollutants From Chemical Recovery Combustion Sources at Kraft, Soda, Sulfite, and Stand-Alone Semichernical Pulp Mills), finalized at 66 FR 3180 (January 12, 2001).]

Based on the legislative history that clarifies Congressional intent, this ‘ interpretation is clearly correct. The Senate Report wrote,

To avoid expenditures by regulated entities which secure no public health or environmental benefit, the Administrator is given discretionary authority to consider the evidence for a health threshold higher than MACT at the time the standard is under review. The Administrator is not required to take such factors into account; that would jeopardize the standard-setting schedule imposed under this section with the kind of lengthy study and debate that has crippled the current program. But where health thresholds are well established, for instance in the case of ammonia, and the pollutant presents no risk of other adverse health effects, including cancer, for which no threshold, can be established, the Administrator may use the threshold with an ample margin of safety (and not considering cost) to set emissions limitations for sources in the category or subcategory. Employing, a health threshold or safety level rather than, the MACT criteria to set standards shall not result in adverse environmental effects which would otherwise be reduced or eliminated.

1990 Leg. Hist. 8511, S. Rep. No 228, 101st Cong. Sess. 171 (1990). See also 1990 Leg. Hist. 8516 (Administrator authorized to use threshold level "in lieu of more stringent ‘best technology’ requirements."). Thus, EPA clearly has the authority to set a risk-based standard.

EPA cannot set a risk-based standard for just any HAP, however. It must be a "threshold pollutant." As the Agency noted in the preamble, HCI is a health threshold pollutant for the purpose of section 112(d)(4). 75 FR 32030.

Even though EPA states that there is no evidence that HCI is a carcinogen (75 FR 32030), some may argue that HCI does not meet Congressional intent for defining threshold pollutant because it has not, been conclusively shown to be non-carcinogenic. That is not necessary according to Congress. As quoted above, Congress explained that ammonia was, a HAP with a "Well-established" threshold for which EPA could set a risk-based standard. A comparison of the IRIS information relating to carcinogenicity for ammonia and HCI shows striking similarities: the information for both ammonia and HCI contains the same notation relating to carcinogenicity, i.e., it has "not undergone a complete evaluation and determination under US EPA’s IRIS program for evidence of human carcinogenic potential." Compare http://www.epasiovincea/iris/subst/0422.htm (Ammonia) with http://www.epa.govincea/iris/substiO396.htm (HCI) (viewed August 12, 2010). There are other similarities as well: i.e., EPA only looked at respiratory effects of both HCI and ammonia, and the RfC for ammonia appears to be based on a LOAEL, not a NOAEL — just like HCI.

In short, EPA has the authority to set a health-based standard for HCI under §112(d)(4). To believe that EPA must make a positive finding of absolutely no cancer risk, i.e., prove a negative, renders this provision a near nullity and belies both the scientific process and Congressional intent.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Walter Tyler
Commenter Affiliation: Invista
Document Control Number: EPA-HQ-OAR-2002-0058-2761.1
Comment Excerpt Number: 16

Comment: Considering the significant impact of this proposed regulation on industry ($2.8 billion from Table 11, 75 FR 32038) the HBCA approach to determine compliance offers the opportunity to achieve the EPA's air quality improvement goals with greater flexibility to the regulated facilities (many of which have unique characteristics and configurations) and to reduced implementation costs for sites to which the HBCA would apply. Such an approach appears permissible according to §112(d)(4) of the Clean Air Act, as detailed in the comments filed by the American Forest & Paper Association.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Melvin E. Keener
Commenter Affiliation: Coalition for Responsible Waste Incineration (CRWI)
Document Control Number: EPA-HQ-OAR-2002-0058-2824.1
Comment Excerpt Number: 16

Comment: One issue that often arises when considering risk-based standards is whether EPA has authority under Section 112 to establish an exposure based emission limit. The concern seems to be that some stakeholders construe the Act's statutory provisions as requiring uniform emission limitations at all facilities, rather than emissions that are measured at places away from the source and that vary from facility to facility. CRWI does not see any legal impediment to establishing exposure based limits.

First, under Section 112, EPA has authority to establish "emission standards." Emission standards are defined to be a requirement established by the State or the Administrator which limits the quantity, rate or concentration of emissions of air pollutants on a continuous basis . . .

to assure continuous emission reduction, and any design, equipment, work prktice or operational standard promulgated under this chapter.

EPA's altemate risk-based emission standard will limit the quantity, rate or concentration of the emissions using operating parameter limitations, or OPLs. These will limit the quantity, rate or concentration of emission. They will be measured at the facility, not at the point of exposure.

Finally, the limitations that EPA is establishing are uniform. They uniformly protect the individual most exposed to emission levels no higher than a hazard index of 1.0.

Thus, CRWI suggests that EPA follow, the process used for Subpart EEE and allow facilities to make a site-specific showing that their emissions will be protective with an ample margin of safety. It will be the responsibility of the facility to make that showing and the permitting authority would have the responsibility to review and approve that site-specific demonstration.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: William A. Moore
Commenter Affiliation: Luminant
Document Control Number: EPA-HQ-OAR-2002-0058-2780.1
Comment Excerpt Number: 18

Comment: EPA should use its authority under § 112(d)(4) to establish health-based standards for HCl and other acid gases. Section 112(d)(4) gives EPA explicit authority to consider health threshold levels, "with an ample margin of safety," when establishing MACT standards for pollutants for which a health threshold has been established. The purpose of this section is to "avoid regulatory costs which would be without public health benefit." S. Rep. No. 101-228, at 148 (1989).

EPA has used this authority in several situations and should do so again in this instance. In fact, the original NESHAP for commercial and industrial boilers and process heaters contained alternative compliance requirements, establishing health-based emissions standards for HCl pursuant to EPA's § 112(d)(4) authority. See 69 Fed. Reg. 55,227, 55,240 (Sept. 12, 2004). EPA has previously determined that HCl has an established health threshold and is not a human carcinogen. See 67 Fed. Reg. 78,046, 78,057 (Dec. 20, 2002) (NESHAP for Lime Manufacturing; EPA exercised its authority under § 112(d)(4) and determined that "further control of HCl emissions from lime manufacturing plants [was] not necessary."); see also 63 Fed. Reg. 18,754, 18,765 (April 15, 1998) (NESHAP for Pulp and Paper; EPA exercised its discretion under § 112(d)(4) and proposed "not to regulate HCl emissions from recovery furnaces."). EPA should again exercise its authority to set health-based rather than technology-based limits where no significant risks to human health are present.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: David A. Buff
Commenter Affiliation: Golder Associates Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2801.1
Comment Excerpt Number: 43

Comment: Ample scientific information supports a determination that HCl, hydrogen fluoride, hydrogen cyanide, and manganese are threshold pollutants and, thus, are eligible to be regulated under §112(d)(4). In addition, EPA has the technical tools and significant factual support for establishing health based emissions limitations for these HAPs that would provide the requisite ample margin of safety to health and the environment. Thus, health based emissions limitations are fully justified on scientific and technical grounds.

EPA should set health based emission limitations for HAP acid gases and, as in the 2004 rule, a health based emissions limit for manganese, which should be implemented in conjunction with a Total Select Metal (“TSM”) standard (where the TSM standard would be an alternative to the PM surrogate, and where a “TSM less manganese” option would be provided when a source elects to comply with the health based compliance alternative for manganese).

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-2702.1
Comment Excerpt Number: 198

Comment: Health Based Alternative.
EPA is authorized by Section 112(d)(4) of the CAA to consider whether emissions from a regulated HAP could affect human health when it establishes MACT standards for a particular category. In doing so, EPA can consider limiting the burden on regulated sources with HAP emissions that pose little or no health hazard by implementing a Health Based Compliance Alternative (HBCA). The HBCA constitutes a real, enforceable emission standard under the law. The HBCA is not an exemption, but rather a compliance option tied to enforceable standards. Sources governed by the HBCA must achieve specific health-based emission standards set by EPA. If these standards are not met, the source must meet the "regular" Boiler MACT compliance requirements. This constitutes a strict standard for a source that chooses the HBCA route to compliance, and should in no way be viewed as an exemption from the Boiler MACT.

The CAA’s multiple compliance option structure, which contemplates application of an HBCA, enables EPA to fulfill its statutory requirement to establish emission standards for the entire Industrial/Commercial/Institutional Boilers and Process Heaters category. Whether a source is governed by the HBCA or the "regular" approach, every source in the category will be subject to an emission standard as required by the statute. EPA established this system of multiple compliance options by relying upon its clear legal authority to include HBCA for threshold pollutants as an option for compliance with the Boiler MACT.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-2702.1
Comment Excerpt Number: 199

Comment: The Absence of a Health Based Compliance Alternative Directly Impacts CIBO Members.
CIBO members operate boilers that burn every conceivable fuel source, including the full range of available coals, wood, natural gas, biomass, coal refuse, and other fuels. These boilers vary greatly in their design, capacities, fuel requirements, air emission characteristics and air pollution control equipment. Some plants use anywhere from two to six different sources of fuel in order to ensure reliability of supply, maintain proper operation, attempt to minimize costs and maintain the viability of production facilities to remain competitive and operational in globally competitive markets.

CIBO members in the manufacturing sector face unprecedented pressure to remain competitive in the world market. Uncertainties such as inflexibility in meeting regulatory standards in the U.S. create additional pressure on companies to shift production overseas or to close down altogether. The HBCA provides CIBO members with compliance flexibility that could prove critical to a company’s decision to continue operating a particular facility or to forego raising customer prices. EPA’s failure to include an HBCA substantially narrows the available options to comply with the MACT standard, and places a further strain on the equipment of CIBO’s members and on the consulting engineering resources that are needed to assist industry in meeting the timelines for compliance.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Quinlan J. Shea
Commenter Affiliation: Edison Electric Institute
Document Control Number: EPA-HQ-OAR-2002-0058-2755.1
Comment Excerpt Number: 1

Comment: EPA should establish health based emissions limitations under section 11 2(d)(4) when appropriate.

EPA has requested comments on whether the agency should impose a health-based standard under section 1 12(d)(4) for HCl and other acid gas emissions. Section 112(d)(4) authorizes EPA to set health-based emissions limitations when establishing standards for HAPs under section 112(d). Section 1 12(d)(4) allows EPA to match the stringency of a HAP emissions limitation to the level determined necessary to fully protect human health. As a result, the standard is no more stringent and no less stringent than needed to protect human health.

The default technology-based method of setting MACT standards is an approach that can and does result in HAP emissions limitations that go well beyond what is needed to protect the public. The clear purpose of section 112(d)(4) is to prevent the promulgation of unduly stringent emission limits simply for the sake of regulation. The legislative history of section 112(d)(4) is clear on this point. In formulating section 112(d)(4), Congress recognized that, “For some pollutants a MACT emissions limitation may be far more stringent than is necessary to protect public health and the environment.” [. Rep. No. 101-228 (1990) at 171.] As a result, section 112(d)(4) was provided as an alternative standard setting mechanism for HAPs “where health thresholds are well-established ... and the pollutant presents no risk of other adverse health effects, including cancer.

Section 112(d)(4)’s inclusion in the 1990 CAA Amendments indicates a congressional intent to retain the health endpoint of the original section 112 – protection of public health with an ample margin of safety. [The ample margin of safety concept also underlies the current residual risk provisions of CAA section 112(f).] If the emissions of a given HAP from all sources in a source category are at a level where public health is protected with an ample margin of safety, then there is no practical need for or benefit from further regulation. EPA should set health-base standards under section 1 12(d)(4) when facts support its use.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Christopher Lish
Commenter Affiliation: Citizen
Document Control Number: EPA-HQ-OAR-2002-0058-2710
Comment Excerpt Number: 2

Comment: I oppose any effort to establish a lesser "health-based" standard for acid gases; no such health-based standard exists.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: David Bonistall
Commenter Affiliation: NewPage Corp
Document Control Number: EPA-HQ-OAR-2002-0058-2920.1
Comment Excerpt Number: 2

Comment: Clean Air Act Section 112(d)(4) authorizes EPA to set health-based emissions limitations when establishing standards for HAPs under § 112(d). Section 112(d)(4) is a powerful tool that enables EPA to match the stringency of a HAP emissions limitation to the level determined necessary to fully protect human health. As a result, the standard is no more stringent and no less stringent than needed to get the job done. The default approach used by EPA to set the proposed standards is a cookie cutter approach that can and does result in HAP emissions limitations that go well beyond what is needed to protect the public from HAP emissions. The clear purpose of § 112(d)(4) is to prevent this from happening.

When the first Industrial Boiler MACT was promulgated in 2004, it included health-based emissions limitations for two HAPs — hydrogen chloride ("HCl") and manganese. These health-based emissions limitations were rigorous standards that demanded accountability. They were a winner for the Agency and the public because public health would have been protected with an ample margin of safety. At the same time these standards were a winner for affected sources because the standards would not have blindly required emissions to be reduced far below the levels needed to assure that the public was protected.

EPA should set health-based emission limitations for HAP acid gases and, like in the 2004 rule, a health-based emissions limit for manganese, which should be implemented in conjunction with a Total Select Metal ("TSM") standard (where the TSM standard would be an alternative to the PM surrogate, and where a "TSM less manganese" option would be provided when a source elects to comply with the health-based compliance alternative for manganese).

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Winslow Sargeant
Commenter Affiliation: US Small Business Administration
Document Control Number: EPA-HQ-OAR-2002-0058-2916.1
Comment Excerpt Number: 2

Comment: EPA Should Have Adopted A Health-Based Compliance Alternative (HBCA)Which Provides Alternative Emission Limits for Threshold Chemicals
EPA has proposed not to exercise its discretion to use section 112(d)(4) to establish a health-based emission standard for HCL and manganese, despite acknowledging that it has such discretion under the Clean Air Act. For its part, the Boiler MACT Panel Report recommends that "EPA adopt the HBCA as a regulatory flexibility option for the Boiler MACT rulemaking. The panel recognizes, however, that EPA has concerns about its legal authority to provide and HBCA under the Clean Air Act, and EPA may ultimately determine that this flexibility is inconsistent with the Clean Air Act." [SBAR Panel Report at 23.]
In fact, EPA has not determined that the 112(d)(4) discretion is inconsistent with the Clean Air Act, nor has it determined that a health-based emission standard cannot be developed for HCl. Rather, EPA simply takes that position that it does have sufficient information to establish an HCl standard under section 112(d)(4), and EPA failed to adequately explain why it is failing to reaffirm the HBCA approach it adopted in the 2004 final boiler rule. Further, the Department of

Justice, stated in its brief defending the previous use of 112(d)(4) in the boiler rule, that claims that the statute precludes the adoption of alternative standards was “meritless.” [Environmental Petitioner’s claim that the statute precludes EPA from establishing alternative standards for threshold pollutants (which petitioners mischaracterize as an exemption) is meritless. Final Brief For Respondent United States EPA, D.C. Cir Case No. 04-1385 (December 4, 2006) at 53-54.] Significantly, small entity representatives commented during the Panel that “adopting an HBCA . . . would be the most important step EPA could take to mitigate the serious financial harm the Boiler MACT would otherwise inflict on small entities . . . [t]herefore, HBCA should be a critical component of any future rule to lesson impact on small entities.” [SBAR Panel Report at 23.] Because EPA has not determined that an HCl HBCA is inconsistent with the Clean Air Act, EPA should have followed the unanimous Panel recommendation and adopted the HBCA for HCl and manganese as a regulatory flexibility option. Such an alternative alone is widely expected to save substantial capital and annual costs, and prevent a significant number of plant shutdowns and job losses, with no detriment to environmental protection. [[In the 2004 final Boiler rule, vacated for other reasons, it was estimated that the HBCA approach saved over $2 billion. See American Forest and Paper Association comments filed August 23, 2010 in this docket. The AF&PA SER comments estimated capital savings in excess of $100 million just for the small facilities in the pulp & paper sector. SBAR Panel Report at 41. It was disappointing that EPA’s discussion of the alternative approach provided no assessment of what costs might be saved by this alternative approach, and that might explain why this alternative was not more seriously considered.]

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Thomas Bakk
Commenter Affiliation: State of Minnesota Senate
Document Control Number: EPA-HQ-OAR-2002-0058-2950
Comment Excerpt Number: 2

Comment: The EPA asked for comment on the use of section 112(d)(4), but chose not to propose the use of the health-based mechanism as an alternative to the MACT standard. We believe that EPA should exercise its discretion to use this provision to set limits for acid gases and manganese. As documented in the AF&PA comments, significant factual support exists for establishing health-based limits for acid gases (hydrogen chloride) and manganese.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Allen Sanders
Commenter Affiliation: AbitibiBowater
Document Control Number: EPA-HQ-OAR-2002-0058-3177.1
Comment Excerpt Number: 3

Comment: AbitibiBowater has already made significant progress in reducing air emissions and can and wants to do more; however, we need greater flexibility to choose more efficient and less costly alternatives that achieve the same health and environmental protection
We recognize and support a goal of continuous environmental improvement, but it must be based on sound science, be achievable and protect against a proven threat to human health or the environment

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Craig Harper
Commenter Affiliation: Collum's Lumber Products, LLC
Document Control Number: EPA-HQ-OAR-2002-0058-2681.1
Comment Excerpt Number: 3

Comment: EPA should retain a health-based compliance option so that facilities are not required to install unnecessary controls.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Mac Gibson
Commenter Affiliation: Alabama Timber Industries, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2717.1
Comment Excerpt Number: 3

Comment: EPA should retain a health based compliance option so that facilities are not required to install unnecessary controls.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Deb Hawkinson
Commenter Affiliation: Hardwood Federation
Document Control Number: EPA-HQ-OAR-2002-0058-2781.1
Comment Excerpt Number: 3

Comment: As others have pointed out, a major challenge for compliance is that the rule is not in line with existing technologies and it does not include an allowance to demonstrate that there is no public health threat with the authority given under 112(d)(4). Therefore, we ask that the rule be reconsidered and the standards be relaxed to come into line with the limits of technology.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Carolyn Van Asten
Commenter Affiliation: Packaging Corp. of America
Document Control Number: EPA-HQ-OAR-2002-0058-3159
Comment Excerpt Number: 3

Comment: In writing the rule, the agency neglected to include the option of compliance through a health based alternative. This alternative would be a legitimate alternative to allow sources to prove that current emission levels do not pose a threat to public health. This option seems to have been completely ignored in developing the rule.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Dennis A. Werblow
Commenter Affiliation: Decorative Panels International, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2599.1
Comment Excerpt Number: 4

Comment: The EPA should utilize its authority in section 112(d)(4) of the Clean Air Act to set health-based emission limits to protect the environment and public health. This would avoid unnecessary controls where emissions of threshold pollutants like HC1, HF and manganese are low enough to be a low health hazard. If the associated incremental ambient concentrations of these threshold pollutants as a result of emissions from a regulated source were sufficiently low, they would qualify for alternative MACT provisions under 112(d)(4).

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Douglas A. McWilliams
Commenter Affiliation: American Municipal Power
Document Control Number: EPA-HQ-OAR-2002-0058-2808.1
Comment Excerpt Number: 5

Comment: EPA Has Ample Authority to Adopt Health-Based Emissions Limitations for Boilers.
Section 112(d)(4) is a powerful tool that enables EPA to match the stringency of a HAP emissions limitation to the level determined necessary to fully protect human health. As a result, the standard is no more stringent and no less stringent than necessary.
As EPA explains in the Proposed Rule, section 112(d) generally requires MACT emissions limitations to be set at a level that reflects the performance of the better performing sources in the given source category or subcategory. Section 112(d)(4) provides an alternative to this basic

approach for pollutants for which a health threshold has been established. For such pollutants, section 112(d)(4) authorizes ITA to "consider such threshold levels, with an ample margin of safety, when establishing emission standards" under section 112(d).
The default technology-based method of setting MACT standards is a cookie cutter approach that results in HAP emissions limitations that sometimes go well beyond what is needed to protect the public from HAP emissions. The clear purpose of section 112(d)(4) is to prevent this from happening. The legislative history of section 112(d)(4) is abundantly clear on this point. In formulating section 112(d)(4), Congress recognized that "[for some pollutants a MACT emissions limitation may be far more stringent than is necessary to protect public health and the environment." S. REP. No. 101-228 (1990) at 171. As a result, section 112(d)(4) was provided as an alternative standard setting mechanism for HAPs "where health thresholds are well-established . . . and the pollutant presents no risk of other adverse health effects, including cancer. . . /d. [Footnote: AMP supports the more detailed scientific analysis of HBELs and the health threshold determinations for HCl, chlorine, hydrogen fluoride, and hydrogen cyanide ("acid gases") are included in the American Forest and Paper Association comments to this rule.]
The first Boiler MACT rule was overturned by the D.C. Circuit but on grounds unrelated to the health-based emissions limitations. Notably, in defending the health-based emissions limitations, the Department of Justice concluded that "Environmental Petitioners' claim that the statute precludes EPA from establishing alternative standards for threshold pollutants (which petitioners mischaracterize as an exemption) is meritless." Final Brief For Respondent United States Environmental Protection Agency, D.C. Cir. Case No. 04-1385 (Dec. 4, 2006) at 53-54.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: David Bonistall
Commenter Affiliation: NewPage Corp
Document Control Number: EPA-HQ-OAR-2002-0058-2920.1
Comment Excerpt Number: 6

Comment: In order to provide additional compliance flexibility for sources, we also recommend EPA includes a health-based TSM compliance alternative along with the TSM emission limit option. Similar to the approach EPA took in the 2004 Boiler MACT rule, in the health-based TSM compliance alternative option, manganese emissions would not be included in the TSM calculation if facility emissions of manganese were below health-based thresholds established using either a lookup table or site specific modeling and risk analysis. Combustion of biomass fuels results in higher ratio of manganese to TSM than combustion of fossil fuels. We believe manganese is a threshold pollutant and it is appropriate to consider in a health-based regulatory approach.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Chris Jamer

Commenter Affiliation: Oregon Forest Industries Council
Document Control Number: EPA-HQ-OAR-2002-0058-2928.1
Comment Excerpt Number: 6

Comment: OFIC urges EPA to evaluate the unintended and negative environmental consequences to implementing these rules. EPA has flexibility in implementing these rules and OFIC urges EPA to consider that the rule should allow facilities to avoid installing controls where there is a reasonable case that emissions are safe.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Thomas D. Evans
Commenter Affiliation: Coastal Resources Company
Document Control Number: EPA-HQ-OAR-2002-0058-2865.1
Comment Excerpt Number: 7

Comment: The emissions of many units affected by the proposed rule pose absolutely no risk to human health or the environment because they are located in rural locations with few, if any, other affected facilities nearby. The "one size fits all" approach of the proposed rule, which treats urban and rural units equally, would force many harmless rural facilities to either inst•A 1 unnecessary and costly controls or shut down. Coastal encourages EPA to exercise its authority under Section 112(d)(4) to establish health-based emission limits, to be applied on a facility-by-facility basis, in order to avoid controls where it can be demonstrated that emissions are safe.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Leslie Sue Ritts
Commenter Affiliation: National Environmental Development Association's Clean Air Project NEDA/CAP
Document Control Number: EPA-HQ-OAR-2002-0058-2794.1
Comment Excerpt Number: 7

Comment: Health Based Emission Limits (HBEL) Should Be Provided in the Rule.

NEDA/CAP's members were disappointed to see that EPA proposed to brush aside the former ICI boiler and process heater MACT provisions for HBELs that would allow sources to demonstrate the absence of health effects for certain pollutants such as manganese and hydrogen chloride, known to have limited air pollution-related public health impacts. Both the policy rationales that are offered, and the assertions that environmental effects such as acid rain are related to these pollutants, are unreasonable and arbitrary. Notably, in NRDC v. EPA, the Court did not find a statutory issue with the HBEL provisions in the ICI boiler and process heater MACT rule, despite a vigorous opposition to those provisions by environmental groups and some states. NEDA/CAP urges the Agency to re-evaluate this option in the coming months, and certainly before the MACT compliance date for this NESHAP. We submit that Congress included section 112(d)(4) in the 1990 Clean Air Act Amendments for a purpose, and that EPA should use its authority under that provision to establish HBELs.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: J. Michael Geers
Commenter Affiliation: Duke Energy
Document Control Number: EPA-HQ-OAR-2002-0058-2765.1
Comment Excerpt Number: 8

Comment: Duke Energy Strongly Supports the Adoption of a Health Based Alternative Limit for Acid Gas HAPS (HCL, CL2, HF and HCN) Under § 112(d)(4)
The proposed rule requires facilities to take costly steps to control emissions even though those emissions may not result in exposures which could pose an excess individual lifetime cancer risk greater than one in one million or exceed thresholds determined to provide an ample margin of safety for protecting public health and the environment. The EPA recognizes in the preamble to the proposed rule that the Administrator has the authority under section 112(d) to establish emissions standards other than conventional MACT standards, in cases where a less stringent emission standard will ensure that a health threshold will not be exceeded with an ample margin of safety. See 75 Fed. Reg. 32030. Duke Energy believes that the EPA should use the authority granted under section 112(d) to establish health based alternative emission standards for the Acid Gas HAPs as compliance option in the final ICI Boiler MACT rule. Section 112(d)(4) is designed to prevent the promulgation of unduly stringent emission limits simply for the sake of regulation. Section 112(d)(4) allows EPA to set health-based limits for certain HAPs based on established health thresholds, rather than having to follow the technology forcing provisions of 112(d)(3).

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Douglas A. McWilliams
Commenter Affiliation: American Municipal Power
Document Control Number: EPA-HQ-OAR-2002-0058-2808.1
Comment Excerpt Number: 8

Comment: The work that EPA performed in support of the HBELs included in the 2004 rule demonstrates that the proposed standards are far more stringent than needed to assure the protection of public health with an ample margin of safety. AMP hereby incorporates by reference (and asks that EPA formally incorporate into the administrative record) all of the support for the health-based compliance alternative included in the record for the 2004 Boiler MACT rule.

EPA asserts in the Proposed Rule that its decision not to propose HBELs "is not contrary to EPA's prior decisions where we found it appropriate to exercise the discretion to invoke the authority in section 112(d)(4) for HC1, since the circumstances in this case differ from previous considerations." 75 Fed. Reg. at 32032. It references "other source categories for which EPA has exercised its authority under section 112(d)(4)," and suggests that boilers and process heaters are more likely to be co-located with other HAP sources and are often located in heavily populated urban areas where many other HAP sources exist. Id. at 32031-32.

Those assertions are astonishing because they ignore the fact that EPA previously "found it appropriate to exercise the discretion to invoke the authority in section 112(d)(4)" as applied to this very category. EPA vigorously defended the HBELs included in the 2004 rule when it was challenged in the D.C. Circuit and dedicated 17 pages of its brief to explaining why its HBELs complied with the requirements of section 112(d)(4). In that brief, EPA acknowledged making the following determinations: (1) both HC1 and manganese have reference concentrations and have not been shown to be carcinogenic, (2) the HBELs provided an ample margin of safety, (3) "health-based standards would not reduce the HAP-related health benefits from the rule because only those facilities with emissions that did not pose a health risk would qualify for the alternative standards," (4) it is inappropriate to consider potential cumulative risks until the residual risk stage of the NESHAP process, and (5) "the potential collateral benefits of controls were not a proper reason to impose control costs under the HAPs program on facilities with HAP emissions that did not pose a public health risk." [Footnote: Final Brief For Respondent United States Environmental Protection Agency, D.C. Cir. Case No. 04-1385 (Dec. 4, 2006) at 59-65, 69.]EPA argued that each of these positions was reasonable, in accord with the law, and entitled to deference. Nothing in the Proposed Rule refutes these determinations.
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EPA's decision to eliminate 11BELs from the Proposed Rule is completely at odds with EPA's prior determination that 11BELs are appropriate and justified for this source category. Although EPA has discretion in setting HBELs, "a reasoned c \plarmtion is needed for disregarding facts and circumstances that underlay or were engendered by [a] prior policy." FCC v. Fox Television Stations, Inc., 129 S. Ct. 1800, 1810 (2009). EPA has offered no such explanation. EPA's failure to acknowledge its prior determination and failure to explain why it has raised as questions issues that previously were resolved (such as how to consider co-located HAP sources and nearby HAP sources) render its decision not to propose HBELs arbitrary and capricious.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Chris M. Hobson
Commenter Affiliation: Southern Company
Document Control Number: EPA-HQ-OAR-2002-0058-2741.1
Comment Excerpt Number: 9

Comment: EPA requested comment on whether it should use its authority under Section 112(d)(4) to set health-based standards for HCl and other acid gases from industrial boilers. EPA has the authority to set health-based limits for certain HAPs based on established health risk thresholds, rather than having to follow the MACT requirements of Section 112(d)(3). EPA should evaluate HAPs for which a health threshold has been established and set health-based standards for such HAPs.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Bill Thomas
Commenter Affiliation: Shuqualak Lumber Company, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2742.1
Comment Excerpt Number: 9

Comment: We believe EPA should retain a health-based compliance option so that facilities are not required to install unnecessary controls if they present very low risk. This will allow EPA to target environmental investments where there is a real need.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Sean M. O'Keefe
Commenter Affiliation: Alexander and Baldwin, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-3196
Comment Excerpt Number: 9

Comment: The Clean Air Act provides EPA with the flexibility to establish health-based emissions limitations (HBELs) for certain pollutants where a MACT emissions limit may be far more stringent than is necessary to protect human health and the environment. The vacated Boiler MACT standard included health-based emissions limitations for manganese and hydrogen chloride (HC1) that helped to reduce compliance costs compared to the technology-based standards that would have otherwise applied without compromising protection of human health and the environment. In the current proposal, however, EPA has elected not to establish any health-based emissions limitations, yet has provided no explanation as to why the justification for HBELs used in support of the earlier rule are no longer valid. A&B believes that the inclusion of HBELs provides an important means for EPA to increase the flexibility of the regulation and to reduce compliance costs without compromising environmental benefits. We therefore urge EPA to restore the HBEL provisions to the rule.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Marvis A. Lewallen
Commenter Affiliation: Clearwater Paper
Document Control Number: EPA-HQ-OAR-2002-0058-2862
Comment Excerpt Number: 11

Comment: The objective of the NESHAP process is to protect public health. Why should any boiler operator be forced to spent resources if their particular boiler is not creating significant incremental risk to the public? EPA is inconsistent when protecting public health through existing programs. Presently several of the action levels EPA uses for drinking water pollutants are based on one excess lifetime cancer case per one hundred thousand exposed individuals. Why would EPA chose a standard for Boiler MACT that would result in reductions in risk of several orders of magnitude from current risks that are already well below this drinking water standard? If one of our boiler systems can be shown to offer excess lifetime cancer risks that are below the well accepted risk level of one lifetime excess lifetime cancer risk per one million exposed individuals and non-carcinogenic risks meaningfully below the accepted chronic exposure levels, why should our system be upgraded at all? Requiring organizations to incur expenses that don't provide meaningful improvement to public health is unacceptable public policy. We respectfully request that EPA reinstitute the health-based compliance alternative in the final version of this rule.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Pamela F. Faggert
Commenter Affiliation: Dominion
Document Control Number: EPA-HQ-OAR-2002-0058-2908.1
Comment Excerpt Number: 14

Comment: EPA has requested comments on whether it should impose a health-based standard under 112(d)(4) for HC1 and other acid gas emissions from industrial boilers. Section 112(d)(4) allows EPA to set health-based limits for certain HAPs based on established health thresholds, rather than having to follow the technology forcing provisions of 112(d)(3). EPA should allow facilities to demonstrate that emissions of certain pollutants do not pose a public health concern. If the emissions of a given HAP from all sources in a source category are at a level where public health is protected with an ample margin of safety, then there is no practical need for or benefit from further regulation. EPA should set health-based standards under § 112(d)(4) when facts support its use. This would target environmental investments where there is a real need based on a rigorous demonstration that pollutants do not pose an adverse risk.
When the first Industrial Boiler MACT was promulgated in 2004, it included health based emissions limitations for two HAPs — HC1 and manganese. While EPA acknowledges its authority under § 112(d)(4) to establish a health-based emissions limitation for threshold pollutants in lieu of a MACT emissions limitation, the Agency proposes not to establish any health based emissions limitations in this proposal. EPA should explain its decision to depart from the approach used in establishing health- based emissions limitations in the 2004 Industrial Boiler MACT.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Jeffrey R.Klieve
Commenter Affiliation: Monsanto Company
Document Control Number: EPA-HQ-OAR-2002-0058-2754.1
Comment Excerpt Number: 15

Comment: Monsanto strongly recommends to USEPA that a Health Based Compliance approach be included in the final rule for the pollutant HCl.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Christy Sammon
Commenter Affiliation: Southeast Lumber Manufacturers Association
Document Control Number: EPA-HQ-OAR-2002-0058-2727.1
Comment Excerpt Number: 16

Comment: The EPA should retain the health-based compliance option (HBCO) contained in the original Boiler MACT rule.

The basis of the original HBCO was that it was a waste of resources to require expensive controls in situations where the source presented no significant health and environmental risk. The EPA has not explained why it has abandoned this reasonable approach.

The statute, at paragraph 112(c)(9), plainly gives EPA the authority to not require controls on source categories that present no appreciable risk. This suggests that Congress intended that EPA need not require controls on sources that are very low risk.
Many of our members were able to meet the very conservative low risk provisions in the original Boiler MACT and this option should be retained in the major source rule.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: John C. deRuyter
Commenter Affiliation: DuPont
Document Control Number: EPA-HQ-OAR-2002-0058-2793.1
Comment Excerpt Number: 18

Comment: A risk-based compliance option under §112(d)(4) is particularly appropriate with respect to emissions of Hydrogen Chloride.

EPA has acknowledged in the prior vacated Subpart DDDDD rule that, in many cases, emissions of hydrogen chloride (HCl) from ICI boilers and process heaters will pose no risk to human health or the environment. Indeed, the available data suggested that a significant proportion of industrial boilers and process heaters do not emit HCl in an amount that would result in an exceedance of applicable health benchmarks. However, this proposed rule does not include a risk or health based approach. DuPont believes that inclusion of a risk based approach under §112(d)(4) is wholly appropriate and most appropriately implemented as a risk-based compliance option. Incorporating this option into the final rule would provide significant cost savings by foregoing the requirement for add-on controls on boilers and process heaters whose emissions do not result in HCl (and other inorganic HAP as appropriate) concentrations that exceed health benchmarks. Dispersion modeling conducted for the prior vacated rule indicated that many affected sources could utilize this means of compliance. This mechanism would ensure that ICI boilers and process heaters whose HCl emissions do exceed these benchmarks are controlled. EPA has ample legal authority under section §112(d)(4) of the CAA to implement this approach.

Such a risk-based compliance option could be implemented in two ways: (1) allow sources whose emissions result in exposures that are below the health threshold for HCl to forego the installation of technological controls, and (2) allow sources, as an alternative to full MACT controls, to control their HCl emissions down to a level that maintains exposures below the health benchmark. DuPont believes that the EPA should include in the final rule a compliance option for HCl that would allow facilities to demonstrate that the HCl concentrations measured at the nearest receptor to the facility cannot reasonably be expected to exceed the health benchmark represented by the RfC, as verified in EPA's IRIS database. Sources that qualify for this compliance option would ensure that the HCl exposures due to the facility's emissions do not increase beyond the RfC. DuPont believes that this approach holds great promise in focusing the rule on eliminating meaningful risks without giving rise to expenditures that provide insignificant meaningful environmental or public health benefit. Simplified, more flexible, and less onerous requirements that can still meet the risk criteria set out in the Clean Air Act would provide a much more cost effective rule while still providing adequate health and environmental protection.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Russ A. Wozniak
Commenter Affiliation: Dow Chemical Company
Document Control Number: EPA-HQ-OAR-2002-0058-2632.1
Comment Excerpt Number: 66

Comment: EPA exercised its discretionary authority under section 112(d)(4) in the 2004 MACT rule for boilers and heaters. As noted by EPA, this standard was vacated on other grounds and the issue of the use of the HBCA was neither rejected or approved by the courts. Thus, Dow comments that section 112(d)(4) remains a viable legal option to use in this most important rulemaking.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 106

Comment: EPA SHOULD CONSIDER HEALTH-BASED THRESHOLDS IN ESTABLISHING EMISSIONS LIMITS. Section 112(d)(4) gives EPA authority to consider a health-threshold established for a pollutant, with an ample margin of safety, when setting a standard for that pollutant. The purpose of this provision is to ensure that the technology driven standards established under section 112(d)(2) and (3) do not overregulate where no human health or environmental gain is to be had. Congress understood that for some pollutants "...a MACT emissions limitation may be far more stringent than is necessary to protect public health and the environment...To avoid expenditures by regulated entities which secure no public health or environmental benefit, the Administrator is given the discretionary authority to consider evidence for a health threshold higher than MACT..."[See Senate Report No.101-228, reprinted in U.S. Code and Congressional and Administrative News, 101st Congress, Second Session 1990 at p. 3556.]

Some of the HAPs regulated by this rule such as hydrogen chloride (HCl) and manganese (Mn) either have established thresholds or meet the requirements for classification as threshold pollutants and should therefore be considered for standard setting under section 112(d)(4).

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Gene Barr
Commenter Affiliation: Pennsylvania Chamber of Business and Industry
Document Control Number: EPA-HQ-OAR-2002-0058-3161
Comment Excerpt Number: 1

Comment: These regulations should provide flexibility for compliance alternatives which can limit costs while maintainingyrotection for Public health and the environment. Overly broad application of "one size fits all" emissions limitations or monitoring protocols can at times lead to imposition of substantial costs and injury to competitive position. EPA should take advantage of the flexibility afforded by Section 112(d)(4) of the Clean Air Act and allow sources reasonable means for demonstrating that their respective emissions do not warrant further control because their respective impacts fall below acceptable health. thresholds. Sources should be afforded reasonable means for demonstrating significant differences in function, design or operating characteristics from hest performing sources such that they can properly avoid being subject to ill-suited requirements resulting from overly broad source categorization.

Response: See preamble for response to final decision on Health Based Compliance Alternative and discussion of MACT floor methodologies.

Commenter Name: Sheila C. Holman
Commenter Affiliation: North Carolina Department of Environment and Natural Resources
Document Control Number: EPA-HQ-OAR-2002-0058-2798.1
Comment Excerpt Number: 1

Comment: In the preamble, EPA stated it would need additional facility-specific emissions information to develop model plants and conduct the dispersion modeling necessary to establish health-based emission limits. These limits would need to be established to ensure that exposure is below the health threshold for this source category, and account for exposures from multiple adjacent sources as well as short-term emission increases. Currently, EPA has very limited information on facility-specific emissions, plant configurations, and overall fence-line characteristics for this source category. Given these data are required to establish health based standards, EPA is requesting such information to evaluate the feasibility of health-based emission limits.

NC DAQ thinks EPA should exercise its Section 112(d)(4) authority to establish health based emission limits for hydrogen chloride (HC1) and other acid gases. This would enable EPA to match proposed HC1 emission limits with the level determined to be health protective. To help accomplish this objective, EPA could use the NC air toxics program as a model methodology and source of dispersion modeling data.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Shelley Schneider
Commenter Affiliation: Nebraska Department of Environmental Quality
Document Control Number: EPA-HQ-OAR-2002-0058-2820.1
Comment Excerpt Number: 1

Comment: 112(d)(4) Health-based Standards
Section 112(d)(4) of the Act states that EPA may take into consideration a health-based standard when establishing emission standards. The NDEQ agrees with EPA that a health-based standard should not be considered in place of a conventional MACT standard for hydrochloric acid and other acid gases. EPA and the state/local permitting authorities do not have adequate information to accurately assess the health risks from facilities.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Winslow Sargeant
Commenter Affiliation: U.S. Small Business Administration
Document Control Number: EPA-HQ-OAR-2002-0058-2916
Comment Excerpt Number: 1

Comment: EPA Should Have Adopted A Health-Based Compliance Alternative (HBCA)Which Provides Alternative Emission Limits for Threshold Chemicals

EPA has proposed not to exercise its discretion to use section 112(d)(4) to establish a health-based emission standard for HCL and manganese, despite acknowledging that it has such discretion under the Clean Air Act. For its part, the Boiler MACT Panel Report recommends that "EPA adopt the HBCA as a regulatory flexibility option for the Boiler MACT rulemaking. The panel recognizes, however, that EPA has concerns about its legal authority to provide and HBCA under the Clean Air Act, and EPA may ultimately determine that this flexibility is inconsistent with the Clean Air Act." [Footnote: SBAR Panel Report at 23.] In fact, EPA has not determined that the 112(d)(4) discretion is inconsistent with the Clean Air Act, nor has it determined that a health-based emission standard cannot be developed for HCl. Rather, EPA simply takes that position that it does have sufficient information to establish an HCl standard under section 112(d)(4), and EPA failed to adequately explain why it is failing to reaffirm the HBCA approach it adopted in the 2004 final boiler rule. Further, the Department of Justice, stated in its brief defending the previous use of 112(d)(4) in the boiler rule, that claims that the statute precludes the adoption of alternative standards was "meritless." [Footnote: "Environmental Petitioner's claim that the statute precludes EPA from establishing alternative standards for threshold pollutants (which petitioners mischaracterize as an exemption) is meritless. Final Brief For Respondent United States EPA, D.C. Cir Case No. 04-1385 (December 4, 2006) at 53-54.] Significantly, small entity representatives commented during the Panel that "adopting an HBCA . . . would be the most important step EPA could take to mitigate the serious financial harm the Boiler MACT would otherwise inflict on small entities . . . [t]herefore, HBCA should be a critical component of any future rule to lesson impact on small entities." [Footnote: SBAR Panel Report at 23.] Because EPA has not determined that an HCl HBCA is inconsistent with the Clean Air Act, EPA should have followed the unanimous Panel recommendation and adopted the HBCA for HCl and manganese as a regulatory flexibility option. Such an alternative alone is widely expected to save substantial capital and annual costs, and prevent a significant number of plant shutdowns and job losses, with no detriment to environmental protection. [Footnote: In the 2004 final Boiler rule, vacated for other reasons, it was estimated that the HBCA approach saved over $2 billion. See American Forest and Paper Association comments filed August 23, 2010 in this docket. The AF&PA SER comments estimated capital savings in excess of $100 million just for the small facilities in the pulp & paper sector. SBAR Panel Report at 41. It was disappointing that EPA's discussion of the alternative approach provided no assessment of what costs might be saved by this alternative approach, and that might explain why this alternative was not more seriously considered.]

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Joseph S. Hensel
Commenter Affiliation: Rochester Public Utilities
Document Control Number: EPA-HQ-OAR-2002-0058-2850.1
Comment Excerpt Number: 1

Comment: EPA should establish health based emissions limitations for acid gases and manganese: In the Industrial Boiler MACT promulgated in 2004, EPA proposed and supported health based emissions limitations (HBEL) for hydrogen chloride (HCl) and manganese. However, in the proposed Industrial Boiler MACT, EPA has arbitrarily chosen not to establish any HBELs nor do they provide a justification for facilities needing to spend millions of dollars in compliance costs on pollutants for which EPA cannot demonstrate an adverse health effect EPA has previously acknowledged that a threshold has been established for both HC1 and manganese below which no adverse effects are observed and concluded that health and safety were protected with an ample margin of safety when the concentrations of these pollutants at the point of exposure were below the threshold for health effects. Furthermore, HBELs are fully justified on scientific and technical grounds. Safe concentrations of HC1 and Mn can be assured, as was proposed in 2004, when facilities meet designated stack heights and fenceline distances sufficient to keep HC1 and Mn below risk thresholds at the point of exposure.

EPA has the legal discretion, under CAA 112(d)(4), and technical justification to set health-based emissions limitations for pollutants "for which a health threshold has been established" thereby substantially reducing the burden of the standard while still providing ample protection to health and the environment. EPA should set HBELs for HAP acid gases and, like in the2004 rule, a health based emissions limit for manganese, which should be implemented in conjunction with a Total Select Metal ("TSM") standard (where the TSM standard would be an alternative to the PM surrogate, and where a "TSM less manganese" option would be provided when a source elects to comply with the health based compliance alternative for manganese).

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Hans-Juergen Obermaier
Commenter Affiliation: Kronospan
Document Control Number: EPA-HQ-OAR-2002-0058-2839
Comment Excerpt Number: 1

Comment: EPA should allow facilities to demonstrate that emissions of certain pollutants do not pose a public health concern. A practical health oriented standard for threshold pollutants like hydrogen chloride and manganese would allow sources to demonstrate their emissions of these compounds pose no adverse risk. The Clean Air Act in §112(d) (4), expressly contemplates the use of such an approach which can be implemented without sacrificing risk reduction benefits. A health threshold standard is critical to the future viability of biomass and other boilers. EPA should make the health threshold standard an integral part of its final rule.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Melissa Mullarkey
Commenter Affiliation: Recycled Energy Development, LLC
Document Control Number: EPA-HQ-OAR-2002-0058-2947.1
Comment Excerpt Number: 1

Comment: The Boiler MACT proposal asks for comments on an approach that would allow facilities to demonstrate that emissions of certain pollutants do not pose a public health threat (p. 32031- 32032). RED believes EPA has the authority under section 112(d)(4) to provide for flexibility where releases don't threaten public health. In a biomass-power facility, for instance, this approach would have EPA allow threshold substances, such as hydrogen chloride and manganese, which in small quantities do not risk a community's health.

RED also suggests EPA adopt a more flexible approach that addresses the diversity of boilers, operations, sectors, and fuels. Such an approach would preserve environmental quality and prevent severe job and productivity losses.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Christopher S. Bond
Commenter Affiliation: United States Senator
Document Control Number: EPA-HQ-OAR-2002-0058-2958.1
Comment Excerpt Number: 2

Comment: EPA proposes cumbersome and costly regulations for these clean biomass burning forest-product facilities that are more appropriate for boilers at industrial and chemical manufacturers or refiners. Similarly, EPA proposes regulations appropriate for incinerators burning scrap tires, plastics and solvents to apply also to forest-product producers using woody biomass byproduct to fuel their operations. In most all cases, EPA proposed emissions levels far exceed what is necessary to protect human health from biomass energy operations. Of course, we cannot compromise our goal of protecting human health. Therefore, the more common-sense solution is to use a health-based standard and allow facilities to show they are not endangering human health. That, after all, is the true goal of the Clean Air Act and is specifically authorized by that Act in section 112(d)(4).

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Richard T. Weber
Commenter Affiliation: Flakeboard America
Document Control Number: EPA-HQ-OAR-2002-0058-2915.1
Comment Excerpt Number: 2

Comment: EPA should allow facilities to demonstrate that emissions of certain pollutants do not pose a public health concern. A practical health oriented standard for threshold pollutants like hydrogen chloride and manganese would allow sources to demonstrate their emissions of these compounds pose no adverse risk. The Clean Air Act in §112(d) (4), expressly contemplates the use of such an approach which can be implemented without sacrificing risk reduction benefits. A health threshold standard is critical to the future viability of biomass and other boilers. EPA should make the health threshold standard an integral part of its final rule.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Gary Chandler
Commenter Affiliation: Association of Washington Business
Document Control Number: EPA-HQ-OAR-2002-0058-2914.1
Comment Excerpt Number: 2

Comment: Establishing health-based emissions limitations for acid gases and manganese under § 112(d)(4). This will enable EPA to adopt a more cost-effective standard that is protective of human health.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Linda Layne
Commenter Affiliation: Citizen
Document Control Number: EPA-HQ-OAR-2002-0058-2977
Comment Excerpt Number: 2

Comment: I strongly support the EPA’s decision to reduce toxic pollution from such boilers, and especially applaud the EPA’s proposed regulation of hydrochloric acid and other dangerous acid gases produced by commercial and industrial boilers. Such acids pose substantial risks to industrial workers, as well as surrounding communities, and must be limited by the strict conventional Maximum Achievable Control Technology standards. I oppose any effort to establish a lesser "health-based" standard for acid gases; no such health-based standard exists.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Ted Sturdevant
Commenter Affiliation: Washington Department of Ecology
Document Control Number: EPA-HQ-OAR-2002-0058-2987.1
Comment Excerpt Number: 2

Comment: We also suggest that EPA consider applying its authority under section 112(d) (4) of the Clean Air Act to use established health thresholds as a basis for alternative compliance requirements.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Jim Weeks
Commenter Affiliation: Michigan Municipal Electric Association
Document Control Number: EPA-HQ-OAR-2002-0058-2795.1
Comment Excerpt Number: 2

Comment: The Need for Health-Bayed Limitations for Acid Gases at Electric Utility Units: EPA should adopt a health-based emissions limitations rather than technology-based standards for electric utility units for the control of acid gases including hydrochloric acid, because the proposed technology standards are unachievable and not justified.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: W. Phillip Reese
Commenter Affiliation: California Biomass Energy Alliance
Document Control Number: EPA-HQ-OAR-2002-0058-2774.1
Comment Excerpt Number: 2

Comment: CBEA recommends exercising your authority in Section 112(d)(4) which already authorizes EPA to set health-based emissions limitations when establishing standards for HAPs under § 112(d). Section 112(d)(4) is a powerful tool that enables EPA to match the stringency of a HAP emissions limitation to the level determined necessary to fully protect human health. As a result, the standard is no more stringent and no less stringent than needed to get the job done.

The default technology-based method of setting MACT standards is a cookie cutter approach that can and does result in HAP emissions limitations that go well beyond what is needed to protect the public from HAP emissions. The clear purpose of § 112(d)(4) is to prevent this from happening. The legislative history of § 112(d)(4) is abundantly clear on this point. In formulating § 112(d)(4), Congress recognized that, "For some pollutants a MACT emissions limitation may be far more stringent than is necessary to protect public health and the environment." 1 As a result, § 112(d)(4) was provided as an alternative standard setting mechanism for HAPs "where health thresholds are well-established ... and the pollutant presents no risk of other adverse health effects, including cancer....”

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Sherilyn Coldwell
Commenter Affiliation: Citizen
Document Control Number: EPA-HQ-OAR-2002-0058-0857
Comment Excerpt Number: 2

Comment: I strongly support EPA’s decision to reduce toxic pollution from such boilers, and especially applaud EPA’s proposed regulation of hydrochloric acid and other dangerous acid gases produced by commercial and industrial boilers. Such acids pose substantial risks to industrial workers, as well as surrounding communities, and must be limited by the strict conventional Maximum Achievable Control Technology standards. I oppose any effort to establish a lesser "health-based" standard for acid gases; no such health-based standard exists.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Jim Weeks
Commenter Affiliation: Michigan Municipal Electric Association
Document Control Number: EPA-HQ-OAR-2002-0058-2795.1
Comment Excerpt Number: 3

Comment: We question why EPA has scrapped its 2004 Industrial Boiler mAcr determination that health-based limitations for hydrogen chloride and manganese, where EPA found that such health-based limits would be adequately protective and could avoid S2 billion in compliance costs. MMEA also wonders why EPA has ignored the recommendation of the Small Business Advocacy Panel for this rule, which identified health-based compliance alternatives as the most importcon step EPA could take to mitigate the serious financial harm the 11-1 MACT would otherwise inflict on small entities using solid fuels nationwide ...."1 [Small Business Advocacy Review Panel, Final Report 23 (Mar. 23, 2009) (emphasis added).

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Robert E. Cleaves
Commenter Affiliation: Biomass Power Association
Document Control Number: EPA-HQ-OAR-2002-0058-2934.1
Comment Excerpt Number: 3

Comment: The proposal asks for comment on an approach that would allow facilities to demonstrate that emissions of certain pollutants do not pose a public health threat. We believe EPA has such flexibility under section 112(d)(4). We believe that provision reflects Congress' intent to provide for flexibility where there is not a public health threat. In such cases, it makes sense to allow that approach in the final rule for threshold substances such as hydrogen chloride and manganese.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: W. Phillip Reese
Commenter Affiliation: California Biomass Energy Alliance
Document Control Number: EPA-HQ-OAR-2002-0058-2774.1
Comment Excerpt Number: 3

Comment: The State of California has used health-risk-based emission limits for two decades, under the AB 2588 Air Toxics "Hot Spots" Program. This established methodology includes specific numerical levels for acceptable risk, and is applied on a facility-by-facility basis. This program has worked for the citizenry of the State and for the biomass power industry. It is an acceptable end effective alternative approach.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Paul Lyskava
Commenter Affiliation: Pennsylvania Forest Products Association
Document Control Number: EPA-HQ-OAR-2002-0058-2906.1
Comment Excerpt Number: 4

Comment: Use of the flexibility and discretionary authority under Section 112(d) of the Clean Air Act on a facility-by-facility basis to set health based emission limitations for certain HAPs.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Ron Lindsey
Commenter Affiliation: Packaging Corporation of America
Document Control Number: EPA-HQ-OAR-2002-0058-3158
Comment Excerpt Number: 4

Comment: I also understand that the Clean Air Act allows EPA to exempt boilers from some requirements if emissions from the boiler would not pose a risk to public health, but this exemption was not included in the proposed rule. Why not? If a boiler doesn't pose a risk to

public health, why regulate it further? Facilities that can show that their emission levels are safe should not be forced to install additional, unnecessary and expensive control equipment.
Mills can’t waste money like that and expect to survive.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Steven W. Koehn
Commenter Affiliation: National Association of State Foresters
Document Control Number: EPA-HQ-OAR-2002-0058-2860.1
Comment Excerpt Number: 4

Comment: Build flexibility into the rule to focus emission limits to where problems exist. Under §112(d)(4) of the Clean Air Act, EPA is authorized to implement health based emissions limits. EPA should utilize this authority to avoid unnecessary controls where emissions do not pose a public health threat. NASF recommends the use of health-based compliance alternatives be made available for HCl and manganese. This approach would still protect public health while eliminating unnecessary financial burdens on facilities that could result from the proposed emissions limits.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Richard Rosvold
Commenter Affiliation: Xcel Energy Services, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2955.1
Comment Excerpt Number: 4

Comment: Xcel Energy supports the establishment of health-based emissions limitations. This option was available under the previous version of the major source industrial boiler MACT standard. This option would allow agencies and facilities to target sources that truly have an impact on public health, while avoiding costly and unnecessary controls, testing, and monitoring on units that pose little risk to public health or the environment.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: David G. Koster
Commenter Affiliation: Holland Board of Public Works
Document Control Number: EPA-HQ-OAR-2002-0058-2907.1
Comment Excerpt Number: 4

Comment: Health-Based Emission Limits for Small Utilities: HBPW also supports health-based emissions limits ("HBELS") as EPA proposed and supported for the Boiler MACT source category under the 2004 Boiler MACT rule. EPA has clear authority to adopt HBELs under section CAA 112(d)(4) for pollutants "for which a health threshold has been established." As EPA previously acknowledged, a threshold below which no adverse effects are observed has been established for both HCI and manganese. In 2004, EPA concluded that health and safety were protected with an ample margin of safety when the concentrations of HCI or manganese at the point of exposure were below the threshold for health effects. These safe concentrations of HCI and Mn can be assured, as was proposed in 2004, when facilities meet designated stack heights and fenceline distances sufficient to keep HCI and Mn below risk thrsholds at the point of exposure. EPA has arbitrarily eliminated HBELs from the proposed rule without providing an adequate explanation for the change.
We believe that EPA has a duty under SBREFA to consider compliance costs and regulatory alternatives that could ease the burden on small entities such as the HBPW. The EPA convened the Small Business Advocacy Panel, which identified health-based compliance alternatives as "the most important step EPA could take to mitigate the serious financial harm the Boiler MACT would otherwise inflict on small entities using solid fuels nationwide...." When EPA adopted a health-based alternative for HCI in 2004, it estimated that affected sources would save $2 billion in compliance costs at no expense to human health or the environment.

We request that the EPA reconsider keeping the HBELs for HCL and manganese in the proposed Boiler MACT rule, or provide a valid explanation for why an HBEL is no longer available to small entities and what now justifies wasting billions of dollars in compliance costs on pollutants for which EPA cannot demonstrate an adverse health effect.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Arthur Blazer
Commenter Affiliation: Council of Western State Foresters
Document Control Number: EPA-HQ-OAR-2002-0058-2832.1
Comment Excerpt Number: 4

Comment: Build flexibility into the rule to focus emission limits to where problems exist. Under 112(d)(4) of the Clean Air Act, EPA is authorized to implement health based emissions limits. EPA should utilize this authority to avoid unnecessary controls where emissions do not pose a public health threat. NASF recommends the use of health-based compliance alternatives be made available for HCl and manganese. This approach would still protect public health while eliminating unnecessary financial burdens on facilities that could result from the proposed emissions limits.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Jennifer Klein
Commenter Affiliation: Ohio Chamber of Commerce
Document Control Number: EPA-HQ-OAR-2002-0058-2901.1
Comment Excerpt Number: 4

Comment: Clean Air Act (CAA) section 112(d)(4) authorizes EPA to set health-based emissions limitations when establishing standards for HAPs. This tool enables EPA to match the stringency of a HAP emissions limitation to the level determined necessary to fully protect human health. Therefore, the standard should be no more stringent and no less stringent than needed to protect human health. However, in the proposed rules, EPA proposes not to establish any health-based emissions limitations. EPA should utilize its authority in the CAA to set health-based emission limits to avoid unnecessary controls where emissions of threshold pollutants, like acid gases and manganese, are low enough to be safe.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Susan Swanson
Commenter Affiliation: Allegheny Hardwood Utilization Group, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2851.1
Comment Excerpt Number: 4

Comment: We request that you revise the rule to be reflective of other available data beyond the top performing units so as to paint a more realistic picture of boiler performance for each HAP and subcategory. We request that you allow for the use of section 112 (d) (4) of the Clean Air Act on a facility-by-facility basis without unnecessarily complicated procedures restricting it's use.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Joe Muehlbach
Commenter Affiliation: Quad/Graphics
Document Control Number: EPA-HQ-OAR-2002-0058-2898.1
Comment Excerpt Number: 5

Comment: In previous MACT standards EPA provided companies with the flexibility to employ alternative compliance approaches that were shown to be protective of public health and approved by the U.S. EPA. U.S. The proposed rules do not provide this compliance flexibility which may needlessly increase the costs of compliance without achieving any measurable environmental protections.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Kirby D. Juntila
Commenter Affiliation: Marquette Board of Light and Power
Document Control Number: EPA-HQ-OAR-2002-0058-3175
Comment Excerpt Number: 6

Comment: The 2004 Industrial Boiler MACT, promulgated in 2004, included a health based emission limit for both hydrogen chloride and manganese emissions. The health based compliance alternative (HBCA) was set at levels determined necessary to fully protect human health for units that meet the criteria. The Shiras Steam Plant, due to the large stack heights and distance to fence lines, was able to comply with the 2004 HBCA requirements. To set standards that require emission reductions far below the levels needed to assure the public and environment are fully protected puts an unnecessary financial burden on small communities. Again, it bears repeating that the applicable boiler at the Shiras Steam Plant demonstrated compliance with the 2004 health based compliance alternative, which was set at a level that fully protected human health with an ample margin of safety. Areas with numerous sources most likely have a larger base to distribute the cost of necessary controls. However, as is the case in Marquette, installing a scrubber on a unit that already demonstrates that it poses no risk to human health and the environment will distribute this unnecessary cost over a population of approximately 21,000 people with an average income of $35,000.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Tim Hagley
Commenter Affiliation: Minnesota Power
Document Control Number: EPA-HQ-OAR-2002-0058-2829.1
Comment Excerpt Number: 7

Comment: EPA should establish health based emissions limitations for acid gases and manganese under § 112(d)(4). In formulating § 112(d)(4), Congress recognized that, "For some pollutants a MACT emissions limitation may be far more stringent than is necessary to protect public health and the environment." [1 S. Rep. No. 101-228 (1990) at 171.] As a result, § 112(d)(4) was provided as an alternative standard setting mechanism for HAPs "where health thresholds are well-established ... and the pollutant presents no risk of other adverse health effects, including cancer...."(ref. S. Rep. No. 101-228 (1990) at 171). EPA has the tools and factual support for establishing health based emission limitations for acid gases and manganese and should do so.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Bill Perdue

Commenter Affiliation: American Home Furnishings Alliance
Document Control Number: EPA-HQ-OAR-2002-0058-2692.1
Comment Excerpt Number: 7

Comment: The establishment of a Health Based Compliance Alternative (HBCA) under CAA Section 112(d)(4) remains a legally defensible and logically viable approach for the Boiler MACT rule. During the litigation over the 2004 Boiler MACT rule, actively defended its adoption of the HBCA. Although the Court of Appeals vacated the Boiler MACT rule for other reasons, they did not rule on the merits of the HBCA. Thus, we urge EPA to proceed with adoption of the HBCA in the current Boiler MACT rule.
By demonstrating negligible offsite risk via an HBCA approach, a participating source benefits the surrounding community by addressing in advance a primary goal of the MACT regulation, which is to reduce offsite risk to safe levels. This approach is very similar to the Residual Risk Review required under CAA Section 112(f)(2) that would otherwise occur at a much later date. The source benefits by implementing a common-sense approach to HAP control that avoids installation of control devices that provide little or no HAP risk reduction at considerable cost. The only remaining portion of residual risk to be addressed after the HBCA is multiple source impact, which is specifically designated in the CAA for completion after implementation of the MACT regulation.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Traylor Champion
Commenter Affiliation: Georgia-Pacific LLC
Document Control Number: EPA-HQ-OAR-2002-0058-2745.1
Comment Excerpt Number: 8

Comment: Congress established the basis for the HBCA
Within Section 112(d) of the 1990 Clean Air Act (CAA), Amendments, which directs EPA to develop Maximum Achievable Control Technology (MACT) standards, there is a subsection, 112(d)(4), that allows EPA to consider whether emissions from a regulated HAP could affect human health in establishing MACT standards for a particular category:
112(d)(4): Health threshold- With respect to pollutants for which a health threshold has been established, the Administrator may consider such threshold level, with an ample margin of safety, when establishing emission standards under this subsection.
As discussed more fully by AF&PA, this section of the CAA provides EPA the authority to establish health based standards for threshold pollutants that are protective of public health with an ample margin of safety.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Al Hankins, Jr.

Commenter Affiliation: Hankins Lumber Company, LLC
Document Control Number: EPA-HQ-OAR-2002-0058-2708.1
Comment Excerpt Number: 9

Comment: We believe EPA should retain a health-based compliance option so that facilities are not required to install unnecessary controls if they present very low risk. This will allow EPA to target environmental investments where there is a real need.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Mark W. Kowlzan
Commenter Affiliation: Packaging Corp. of America
Document Control Number: EPA-HQ-OAR-2002-0058-2913.1
Comment Excerpt Number: 9

Comment: We believe that there are legitimate reasons for having HBELs for HCI and manganese. Section 112(d)(4) affords EPA an alternative to a discrete MACT limit wherein a HAP emissions limitation can be established at a level that is fully protective of human health, including an adequate margin of safety. By selecting the (default) technology-based approach to establishing a MACT standard EPA goes beyond what is needed to protect the public from HAP emissions.

The health-based emissions limitations established in the 2004 MACT rule were developed under rigorous standards that protected public health with an ample margin of safety. By not incorporating RBCA into the proposed rule, EPA isforcing PCA to spend inordinate amounts of capital to reduce emissions that do not present a demonstrable risk to public health. EPA can and should set health-based standards that are clearly and unequivocally allowed by the Clean Air Act.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Eveleen Muehlethaler
Commenter Affiliation: Port Townsend Paper Corp
Document Control Number: EPA-HQ-OAR-2002-0058-2871.1
Comment Excerpt Number: 9

Comment: We recommend that EPA reconsider the Boiler rule to include health-based emissions limitations for certain pollutants.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Traylor Champion
Commenter Affiliation: Georgia-Pacific LLC
Document Control Number: EPA-HQ-OAR-2002-0058-2745.1
Comment Excerpt Number: 9

Comment: EPA has utilized this mechanism in the vacated Boiler MACT rule and several other MACT standards.
In the original 2004 Boiler MACT rule, EPA determined that two HAPs, hydrogen chloride (HCl) and manganese (Mn), are threshold pollutants that do not pose a significant health risk at a potentially large proportion of regulated sources. If affected sources were able to demonstrate that health benchmarks could be met for these HAPs, emission controls for these materials were not necessary.
Similar considerations for addressing HCl as a threshold pollutant have been included in several other National Emission Standards for Hazardous Air Pollutants standards:
1. Hazardous Waste Combustors (Phase I Final Replacement Standards and Phase II)
2. Chemical Recovery Combustion Sources At Kraft, Soda, Sulfite, And Stand-Alone Semichemical Pulp Mills;
3. Portland Cement Manufacturing Industry; and
4. Chlorine and Hydrochloric Acid Emissions From Chlorine Production.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Nilaksh Kothari
Commenter Affiliation: Manitowoc Public Utilities
Document Control Number: EPA-HQ-OAR-2002-0058-2810.1
Comment Excerpt Number: 9

Comment: MPU supports health-based emissions limits ("HBELs") as EPA proposed and supported for the Boiler MACT source category under the 2004 Boiler MACT rule. EPA has clear authority to adopt HBELs under section CAA 112(d)(4) for pollutants "for which a health threshold has been established." As EPA previously acknowledged, a threshold below which no adverse effects are observed has been established for both HCl and manganese.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Tom Midyett
Commenter Affiliation: Tennessee Paper Council
Document Control Number: EPA-HQ-OAR-2002-0058-2691.1
Comment Excerpt Number: 9

Comment: Section 112(d)(4) allows EPA to establish health-based emissions limitations (HBELs) for pollutants in lieu of a MACT limitation. In the proposed rule, EPA opted not to include any HBELs citing information limitations (i.e., cumulative impacts of co-located sources, multiple HAP emissions from sources, etc.). We believe that there are legitimate reasons for having HBELs for HCl and manganese. Section 112(d)(4) affords EPA an alternative to a discrete MACT limit wherein a HAP emissions limitation can be established at a level that is fully protective of human health that includes an adequate margin of safety. By selecting the (default) technology-based approach to establishing a MACT standard EPA goes beyond what is needed to protect the public from HAP emissions.

The 2004 version of the Industrial Boiler MACT included health based emissions limitations for HCl and manganese.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Bill Wemhoff
Commenter Affiliation: National Rural Electric Cooperative Association
Document Control Number: EPA-HQ-OAR-2002-0058-2835.1
Comment Excerpt Number: 10

Comment: Section § 112(d)(4)'s inclusion in the 1990 CAA Amendments indicates a Congressional intent to retain the health endpoint of the original § 112 -- protection of public health with an ample margin of safety. If the emissions of a given HAP from all sources in a source category are at a level where public health is protected with an ample margin of safety, then there is no practical need for or benefit from further regulation. NRECA encourages EPA to set health-base standards under § 112(d)(4) when facts support its use.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Lee B. Zeugin
Commenter Affiliation: Utility Air Regulatory Group
Document Control Number: EPA-HQ-OAR-2002-0058-2880.1
Comment Excerpt Number: 10

Comment: EPA has requested comments on whether it should impose a health-based standard under § 112(d)(4) for HCl and other acid gas emissions from IBs. See 75 Fed. Reg. at 32,030. Section 112(d)(4) is designed to prevent the promulgation of unduly stringent emission limits simply for the sake of regulation. Section 112(d)(4) allows EPA to set health-based limits for certain HAPs based on established health thresholds, rather than having to follow the technology forcing provisions of § 112(d)(3). As a practical matter, § 112(d)(4) applies to non-carcinogenic HAPs [Almost without exception, EPA assumes a linear, no-threshold dose-effect relationship for HAPs that are classified as carcinogens.] for which EPA has established a health threshold such as a reference concentration ("RfC") or a reference dose ("RfD"). EPA defines a reference concentration in its Information Risk Information System ("IRIS") database as "[a]n estimate (with uncertainty spanning perhaps an order of magnitude) of a continuous inhalation exposure to the human population (including sensitive subgroups) that is likely to be without an appreciable risk of deleterious effects during a lifetime."[The definition for a reference dose is essentially the same except it focuses on exposures by pathways other than inhalation.] Thus, human exposures to a HAP at levels below its RfC are considered "safe" particularly given the uncertainty factors that EPA includes as part of its derivation of a RfC.

Congress' inclusion of § 112(d)(4) in the 1990 CAA Amendments indicates an intent to retain the health endpoint of the original § 112 -- protection of public health with an ample margin of safety.[The ample margin of safety concept also underlies the current residual risk provisions of CAA § 112(f).] If the emissions of a given HAP from all sources in a source category are at a level where public health is protected with an ample margin of safety, then there is no practical need for or benefit from further regulation. EPA should set health-based standards under § 112(d)(4) when facts support its use.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Gary Melow
Commenter Affiliation: Michigan Biomass
Document Control Number: EPA-HQ-OAR-2002-0058-2776.1
Comment Excerpt Number: 10

Comment: EPA should reinstate the risk assessment option for HCL and manganese
In the original boiler MACT rule, EPA offered a risk assessment option for sources that could demonstrate acceptable ambient impacts of HCL or manganese in lieu of complying with an emission limit. We urge EPA to reinstate this option for the proposed Boiler MACT Rule. Biomass boilers are typically located in rural areas, so concerns with multiple sources of exposure in heavy industrial areas discussed on pages 32031 to 32032 is not a concern for our sources.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: David W. Peightal
Commenter Affiliation: Dakota Gasification Company
Document Control Number: EPA-HQ-OAR-2002-0058-3179
Comment Excerpt Number: 11

Comment: EPA should consider health-based impact as part of the evaluation process. Facilities in rural areas should not be required to add pollution controls. DGC is an example of this because there is a sparse residential population of only 51 residents within a 4.5 mile radius of our facility. Also, pollution controls may be unnecessary considering physical parameters at DGC which would include the dispersion environment and the 400 foot stack height. DGC is requesting that EPA use its discretion to set a health-based alternative to numeric limits. If a source can demonstrate that emissions are below the agencies risk exposure limit for public health, that option would make sense in lieu of extremely low emission limits. DGC encourages EPA to include a health threshold option in the final rule.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Tracy Smith
Commenter Affiliation: Coastal Forest Products
Document Control Number: EPA-HQ-OAR-2002-0058-2872.1
Comment Excerpt Number: 11

Comment: The EPA should retain the health-based compliance option (HBCO) contained in the original Boiler MACT rule.

The basis of the original HBCO was that it was a waste of resources to require expensive controls in situations where the source presented no significant health and environmental risk. The EPA has not explained why it has abandoned this reasonable approach.

The statute, at Section 112(c)(9) and 112(d)(4) , plainly gives EPA the authority to not require controls on categories or sources that present no appreciable risk. This suggests that Congress intended that EPA need not require controls on sources that are low risk.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Dell Majure
Commenter Affiliation: Kimberly Clark Corp.
Document Control Number: EPA-HQ-OAR-2002-0058-2779.1
Comment Excerpt Number: 12

Comment: Scientific information supports a determination that HCl, HF, HCN, and Mn are threshold pollutants and, thus, are eligible to be regulated under § 112(d)(4). In addition, the Agency has the technical tools and significant factual support for establishing health based emissions limitations for these HAPs that would provide the requisite ample margin of safety to health and the environment. EPA should set health based emission limitations for HAP acid gases and, like in the 2004 rule, a health based emissions limit for manganese, which should be implemented in conjunction with a Total Select Metal (TSM) standard (where the TSM standard would be an alternative to the PM surrogate, and where a “TSM less Mn” option would be provided when a source elects to comply with the health based compliance alternative for Mn).

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Paul N. Cicio
Commenter Affiliation: Industrial Energy Consumers of America
Document Control Number: EPA-HQ-OAR-2002-0058-2752.1
Comment Excerpt Number: 12

Comment: Health Based Compliance Alternative - EPA should exercise its authority under 112(d)(4) of the Clean Air Act to establish a Health Based Compliance Alternative.
Congress anticipated the need for alternative, risk-based methods to enable a more cost-effective means of demonstrating compliance with the MACT standards. IECA agrees with EPA that §112(d)(4) of the Clean Air Act grants the Administrator the authority to exercise discretion whether to establish a risk-based emission limit such as a Health-Based Compliance Alternative (HBCA).

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Allyn Ford
Commenter Affiliation: Roseburg Forest Products
Document Control Number: EPA-HQ-OAR-2002-0058-3163
Comment Excerpt Number: 12

Comment: EPA has other, less economically devastating means available to minimize HAP emissions and to protect public health:

Section 112(d) of the Clean Air Act allows EPA to integrate into its rules the ability for facilities to demonstrate that risks from certain pollutants are safe. This certainly should be allowed in the case of biomass-fired combustion units. As discussed above, costs associated with controlling biomass units are particularly significant since they are burning relatively clean fuel. Allowing these facilities to demonstrate that the fuels they burn and the resulting emissions do not pose an unsafe risk will inject some reason into the standards. It will most certainly serve to save jobs.

A limited risk-based approach could be integrated into the rule by creating a total select metals standard as an alternative approach to the particulate matter standard. Once in place, provide for an option allowing facilities to demonstrate that the manganese emissions do not pose an unsafe risk. The same could be true of HCI emissions.

A risk-based approach truly gets at the issue of protecting human health, whereas surrogate pollutants and best performing emission rates may be overprotective at some facilities while being less than protective at others. A risk based approach is also based on site-specific data that affects dispersion and hence, risk. For instance, two facilities with similar emission rates, but different stack heights, diameters, flowrates, topography, and meteorology may have wildly different impacts to human health. For this reason, Roseburg Forest Products believes that the proposed MACT rules likely do not have an adequate level of control at some facilities while severely and unnecessarily penalizing other facilities that do not have an adverse impact. The proposed blanket approach to HAP regulation will have significant impacts on facilities and may even cause some facilities to close that do not have a significant impact on human health and the environment.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: David P. Tenny
Commenter Affiliation: National Alliance of Forest Owners
Document Control Number: EPA-HQ-OAR-2002-0058-2750.1
Comment Excerpt Number: 14

Comment: NAFO further believes that EPA should exercise its authority under CAA §112(d)(4) to establish a health-based emissions limitation for HCl and manganese. This approach would ensure that public health is protected while eliminating the extreme cost to industry that could result from the proposed MACT emissions limitations.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Ted Michaels
Commenter Affiliation: Energy Recovery Council
Document Control Number: EPA-HQ-OAR-2002-0058-2831.1
Comment Excerpt Number: 19

Comment: When the first Industrial Boiler MACT was promulgated in 2004, it included health based emissions limitations for two HAPs – HCl and manganese. These health-based emissions limitations were rigorous standards that demanded accountability. They were a winner for the Agency and the public because public health would have been protected with an ample margin of safety. At the same time these standards were a winner for affected sources because the standards would not have blindly required emissions to be reduced far below the levels needed to assure that the public was protected. It was estimated at the time that these health based standards would have saved over $2 billion in compliance costs, as compared to the technology-based standards that otherwise would ave applied.

In its proposed Major Boiler MACT rule, EPA acknowledges its authority under Section 112(d)(4) to establish a health-based emissions limitation for threshold pollutants in lieu of a MACT emissions limitation. However, the Agency proposes not to establish any health based emissions limitations "[g]iven the limitations of the currently available information (i.e., the HAP mix where boilers are located, and the cumulative health impacts from co-located sources), the environmental effects of HCl, and the significant co-benefits of setting a conventional MACT standard for HCl." (75 FR 32032). Nevertheless, EPA asks for comment on a wide range of issues related to the justification for setting health based emissions limitations and the method by which they should be set.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: David M. Kiser
Commenter Affiliation: International Paper Company
Document Control Number: EPA-HQ-OAR-2002-0058-2777.1
Comment Excerpt Number: 28

Comment: IP supports a health based control alternative because it is allowed by statute and should lead to pragmatic decisions regarding HCl and other pollutants.

EPA has the ability under CAA section 112(d)(4) to set health-based emission limits. IP encourages EPA to exercise its discretion to do so. The current limits are more stringent than needed to assure appropriate protection of health and the environment from industrial boiler HAP emissions. Using its discretionary authority under the CAA would allow EPA to craft appropriate rules that should yield more pragmatic regulatory results.

Every opportunity to minimize excessive or unnecessary control costs beyond what is needed from a health and environmental protection perspective should be employed to minimize the cost of the Boiler MACT regulation, which under any circumstances appears will be exceedingly high for the environmental and public benefit it provides.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Christopher S. Colman
Commenter Affiliation: Hovensa LLC
Document Control Number: EPA-HQ-OAR-2002-0058-2863.1
Comment Excerpt Number: 39

Comment: In many cases, remote/island facilities are located in areas which have few or no other major or even significant area sources. For tropical islands, the unique meteorological conditions of the area result in resident population being exposed infrequently to emissions from the facility. For example, this is the wind rose for St. Croix:

The result is that emissions from this refinery, which is located on the south shore of St. Croix, rarely blow inland. For this reason, we believe that EPA can also use its authority under Section 112(d)(4) to set emissions standards for island/remote facilities, particularly given the compelling differences between these facilities and mainland facilities.

A good example for health based regulation for island facilities may be mercury, where data available clearly indicates that fuel oil combustion presents no real relative risk. Mercury in coal is two orders of magnitude higher than mercury in fuel oil, based on HOVENSA's review of information in the docket. EPA estimated mercury present in residual fuel oil as being no more than 400 kg annually.37 This quote illustrates the exceptionally limited risk posed by residual fuel oil combustion:
"Significance. The mass of coal burned in the U.S. annually (1012 kg/y) is approximately the same as the mass of oil refined in the U.S. annually (13). The concentration of mercury in all U.S coal (coal rank volume corrected) is approximately 100 g/kg (1, 2). From the measured mean concentration for total mercury in oil and total annual volume (2004), oil that passes through U.S. refineries contains approximately 3 metric tons of mercury. The maximum amount of mercury released to the ecosphere from oil processed in the U.S. is, therefore, approximately less than 5% of that which may be derived from burning coal in any given year."38
There is little environmental or health based reason to force HOVENSA and other remote facilities to retrofit with expensive controls to address mercury from fuel oil combustion.
[Footnote 37: Mercury in Petroleum and Natural Gas: Estimation of Emissions from Production, Processing, and Combustion, Wilhelm, 2001, EPA-600/R-01-066.]
[Footnote 38: Mercury in Crude Oil Processed in the United States (2004), S. Mark Wilhelm,* Lian Liang,† Deborah Cussen,‡ and David A. Kirchgessner, Mercury Technology Services, 23014 Lutheran Church Rd., Tomball, Texas, Cebam Analytical, Seattle, Washington, Frontier Geosciences, Seattle, Washington, and U.S. Environmental Protection Agency, Research Triangle Park, North Carolina Environ. Sci. Technol, 2007.]

Response: See preamble for response to final decision on Health Based Compliance Alternative. See preamble for discussion of non-continental subcategory.

Commenter Name: Alicia Oman
Commenter Affiliation: National Association of Manufacturers
Document Control Number: EPA-HQ-OAR-2002-0058-2845.1
Comment Excerpt Number: 70

Comment: Section 112(d)(4) is a tool that enables EPA to match the stringency of a HAP emissions limitation to the level determined necessary to fully protect human health. As a result, the standard is no more stringent and no less stringent than needed to get the job done. As EPA explains in the proposed rule, 112(d) generally requires MACT emissions limitations to be set at a level that reflects the performance of the better performing sources in the given source category or subcategory. Section 112(d)(4) provides an alternative to this basic approach for pollutants for which a health threshold has been established. For such pollutants, 112(d)(4) authorizes EPA to "consider such threshold levels, with an ample margin of safety, when establishing emission standards" under 112(d).

The default technology-based method of setting MACT standards is a cookie cutter approach that can and does result in HAP emissions limitations that go well beyond what is needed to protect the public from HAP emissions. The clear purpose of 112(d)(4) is to prevent this from happening. The legislative history of 112(d)(4) is abundantly clear on this point. In formulating 112(d)(4), Congress recognized that, "For some pollutants a MACT emissions limitation may be far more stringent than is necessary to protect public health and the environment." [Footnote: S. Rep. No. 101-228 (1990) at 171.] As a result, 112(d)(4) was provided as an alternative standard setting mechanism for HAPs "where health thresholds are well-established ... and the pollutant presents no risk of other adverse health effects, including cancer...." [Footnote: S. Rep. No. 101-228 (1990) at 171.]

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Alicia Oman
Commenter Affiliation: National Association of Manufacturers
Document Control Number: EPA-HQ-OAR-2002-0058-2845.1
Comment Excerpt Number: 71

Comment: When the first Industrial Boiler MACT was promulgated in 2004, it included health based emissions limitations for HCl and manganese. Under both of these standards, a site-specific risk assessment had to be conducted to prove that emissions from the site were low enough that human health would be protected, with an ample margin of safety. Actual emissions testing of all affected emissions points was required to verify the emissions rates used in the risk assessment. All relevant site parameters were required to be recorded in the site's Title V operating permit to provide assurance over time that public health would be adequately protected. [Footnote: See, generally, 69 Fed. Reg. 55218, 55227-55228 (Sept. 13, 2004).]

In short, these health-based emissions limitations were rigorous standards that demanded accountability. At the same time these standards were a winner for affected sources because the standards would not have blindly required emissions to be reduced far below the levels needed to assure that the public was protected. It was estimated at the time that these health based standards would have saved over $2 billion in compliance costs, as compared to the technology-based standards that otherwise would have applied. The first Industrial Boiler MACT was overturned by the D.C. Circuit, but on grounds unrelated to the health based emissions limitations. Notably, in defending the health based emissions limitations, the Department of Justice concluded that, "Environmental Petitioners' claim that the statute precludes EPA from establishing alternative standards for threshold pollutants (which petitioners mischaracterize as an exemption) is meritless." [Footnote: Final Brief For Respondent United States Environmental Protection Agency, D.C. Cir. Case No. 04- 1385 (Dec. 4, 2006) at 53-54.]

Giving full consideration to the use of health-based standards is particularly important in the wake of the series of decisions from the D.C. Circuit that have progressively limited EPA's discretion to make common-sense decisions when setting MACT standards under 112. EPA's authority to set health based standards under 112(d)(4) is unassailable. For appropriate HAPs and where the relevant facts substantiate its use, EPA can set health-based standards with full confidence that they will survive judicial review.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Lee B. Zeugin
Commenter Affiliation: Utility Air Regulatory Group
Document Control Number: EPA-HQ-OAR-2002-0058-2880.1
Comment Excerpt Number: 96

Comment: We believe, perhaps because of the compartmentalization within EPA,[The proposed IB MACT rule was prepared by the Sector Polices and Programs Division within EPA's Office of Air Quality Planning and Standards (OAQPS). The Health and Environmental Impacts Division, also within
OAQPS, is responsible for assessing risks of air pollution and setting national ambient air quality standards.] the Agency has overlooked a fundamental issue with respect to its treatment of HC1 and HF. To advance this argument, we quote the following sections from the Clean Air Act. For the purpose of establishing national primary and secondary ambient air quality standards, the Administrator shall within 30 days after the date of enactment of the Clean Air Act Amendments of 1970 publish, and from time to time thereafter revise, a list which includes each air pollutant —
A. emissions of which, in his judgment, cause or contribute to air pollution which may reasonably be anticipated to endanger public health or welfare;
B. the presence of which in the ambient air results from numerous and diverse mobile or stationary sources.[42 U.S.C. §7408(a)(1).]

Clearly HC1 and HF would qualify as potential criteria pollutants (e.g., emitted by numerous and diverse sources). Notwithstanding section 112(d)(4), if the Administrator has any reason to believe the levels of either HC1 or HF in the ambient air [This includes emissions not only from industrial boilers but also emissions from all mobile and stationary sources.] reasonably endanger public health or welfare, she is derelict in her duties for failing to set a national ambient air quality standard (NAAQS). If we conclude the Administrator is not derelict in her duties, then the only logical conclusion to reach is that neither HCl nor HF concentration in the ambient air endanger public health or welfare. Thus, all of the Agency's tortured discussion about the difficulty of using the authority provided for in section 112(d)(4) is really unnecessary because neither HC1 nor HF pose any health risks.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 107

Comment: Basis for a section 112(d)(4) Standard. section 112(d)(4) enables EPA to establish a standard that is not purely technology driven and to consider the health-threshold of a pollutant is setting that standard. This provision expresses Congress" concern that sources not be over-regulated by technology when technology-driven emission reductions go beyond was is necessary to protect human health with an ample margin of safety.

In the 2004 Boiler rule, EPA determined that two HAPs commonly emitted from solid fuel industrial boilers, hydrogen chloride (HCl) and manganese (Mn), are threshold pollutants. Similar considerations for addressing HCl as a threshold pollutant have been included in 1) NESHAP; Final Standards for Hazardous Air Pollutants for Hazardous Waste Combustors (Phase I Final Replacement Standards and Phase II); Final Rule; 2) NESHAP; Proposed Standards For Hazardous Air Pollutants From Chemical Recovery Combustion Sources At Kraft, Soda, Sulfite, And Stand-Alone Semichemical Pulp Mills; 3) NESHAP:Portland Cement Manufacturing Industry; and 4) NESHAP: Chlorine and Hydrochloric Acid Emissions From Chlorine Production. In the absence of specific scientific evidence to the contrary, it has historically been EPA's policy to classify non-carcinogenic effects as threshold effects, as demonstrated in the above rulemakings.

In the 2004 Boiler rule EPA concluded the following:

Hydrogen chloride is the chief acid gas HAP from solid fuel combustion and emissions are related to chloride and chlorine content in fuel. Hydrogen chloride and chlorine are threshold HAPs with associated similar effects and established Reference Concentrations (RfC), such that the combined inhalation risks of these HAPs can be considered collectively.

Manganese is a threshold HAP metal, which is a chief risk driver for wood-fired boilers. The rule included emission standards for Total Selected Metals (TSM), of which manganese was a component, but the rule exempted manganese from the TSM calculation.

Section 112(d)(4) requires that all boilers (i.e, from the same MACT source category) at a single facility not significantly contribute to risk. It does not require risk evaluation of other HAPs with different types of health effects or contribution from other sources or background concentrations, as presently suggested in the proposed rule. EPA stated the basis for this determination in response to comments that cumulative risks should be evaluated under the health based compliance alternative.

EPA responded that section 112(d)(4) does not indicate that a risk assessment should be undertaken, but simply that the threshold level of a particular HAP should be considered and that it is appropriate to consider cumulative risk under section 112(f), which requires the evaluation of residual risk after the implementation of MACT standards.

The preamble to this 2010 boiler proposed rule deviates from EPA's direct interpretation of section 112(d)(4) in the 2004 Boiler rule by expanding the consideration of a pollutant's threshold level to other unrelated issues such as the co-benefit of technology controls reducing emissions of criteria pollutants. Although such objectives may appear to be meritorious from an overall environmental protection perspective, there is no indication from the language of

112(d)(4) that other factors besides human health effects of specific threshold HAPs are intended to be considered.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Jerry Osheka
Commenter Affiliation: PPG Industries
Document Control Number: EPA-HQ-OAR-2002-0058-2938.1
Comment Excerpt Number: 8

Comment: EPA has the authority to set health-based emissions standards and needs to include a Health-Based Compliance Alternative (HBCA) for meeting the HCl (acid gases) emissions limits. Section 112(d)(4) authorizes EPA to set health-based emissions limitations when establishing standards for HAPs under § 112(d). Section 112(d)(4) is a powerful tool that enables EPA to match the stringency of a HAP emissions limitation to the level determined necessary to fully protect human health. As a result, the standard is no more stringent and no less stringent than needed to get the job done. The legislative history of § 112(d)(4) is abundantly clear on this point. In formulating § 112(d)(4), Congress recognized that, “For some pollutants a MACT emissions limitation may be far more stringent than is necessary to protect public health and the environment.” 2 As a result, § 112(d)(4) was provided as an alternative standard setting mechanism for HAPs “where health thresholds are well-established ... and the pollutant presents no risk of other adverse health effects, including cancer....”[footnote: S. Rep. No. 101-228 (1990) at 171.] PPG urges EPA to establish health-based emissions limits for sources to demonstrate adequate protection of human health as allowed under §112(d)(4) of the Clean Air Act, by considering emissions of HCl, Cl2, HF and HCN from the affected source in comparison against the appropriate RfC. PPG contends that evaluating a source’s HCl emissions against the RfC will provide ample protection to public health with a margin of safety.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Wayne Brandt
Commenter Affiliation: Minnesota Forest Industries
Document Control Number: EPA-HQ-OAR-2002-0058-3220
Comment Excerpt Number: 2

Comment: Alternative Health-Based Limits Under Section 112(d)(4).
In the proposed rule, EPA recognizes its authority under section 112(d)(4) of the Clean Air Act to set health-based emission limits as an alternative to the MACT standards if it determines that such limits adequately protect public health, including a margin of safety. This mechanism is intended to be used when MACT standards may be more stringent than is necessary to protect public health and the environment. The result would be a rule that is protective, but eliminates costs that are unnecessary.

The EPA asked for comment on the use of section 112(d)(4), but chose not to propose the use of the health-based mechanism as an alternative to the MACT standard. We believe that EPA should exercise its discretion to use this provision to set limits for acid gases and manganese. As documented in the AF&PA comments, significant factual support exists for establishing health-based limits for acid gases (hydrogen chloride) and manganese.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

HBCA: Health Effects of HCl and Mn

Commenter Name: Tim Keneally
Commenter Affiliation: KapStone Paper and Packaging Corporation
Document Control Number: EPA-HQ-OAR-2002-0058-2673.1
Comment Excerpt Number: 2

Comment: KapStone also questions the stringent limits when the results from EPA's air toxics at school monitoring program that was conducted at Chicora Elementary School located in North Charleston, South Carolina showed results from HAP pollutants well below the screening values established by EPA. Our cogeneration boiler in North Charleston is the largest industrial source located in close proximity to Chicora Elementary School, however our "best performing" boiler may not meet the proposed Industrial Boiler MACT standards. The recent monitoring at the school shows that stringent reductions imposed by the proposed Boiler MACT standard are not necessary to meet health-based compliance concentrations.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: G. Vinson Hellwig and Robert H. Colby
Commenter Affiliation: National Assocation of Clean Air Agencies
Document Control Number: EPA-HQ-OAR-2002-0058-2841.1
Comment Excerpt Number: 38

Comment: Many of the HAPs for which HCl and PM are surrogates are potential or demonstrated carcinogens. Moreover, because no meaningful studies have been conducted, EPA has identified both HCl and manganese as unclassifiable for carcinogenicity. For this reason it cannot be asserted that a "well-established" threshold exists and that there is no risk of cancer. EPA's Integrated Risk Information System (IRIS) reports that no studies have identified a No Observable Effects Level (NOEL) for neurological effects for manganese. See http://www.epa.gov/iris/subst/0373.htm;http://www.epa.gov/ncea/iris/subst/0396.htm.] Further, the CAA requires that a section 112(d)(4) standard include "an ample margin of safety." EPA's IRIS report concludes that the scientific confidence in the Oral Reference Concentration for HCl employed by EPA in the ICI Boiler “risk-based exemption” is “low.”[The IRIS report concludes “[t]he chronic study used only one dose and limited toxicological measurements. The supporting data consist of two subchronic bioassays; the database does not provide any additional chronic or reproductive studies. Therefore, low confidence was recommended for the study, database, and the RfC”.] For this reason, it cannot be said that the “well established” threshold that provides an “ample margin of safety” has been established for HCl. Broader approaches for alternate emission standards were specifically rejected by Congress in the development of section 112.[Congress specifically rejected an amendment that would have provided that individual sources “could comply with alternative emission limitations in lieu of standards under this section, if the owner or operator presents evidence sufficient to demonstrate that emissions from the source in compliance with such limitations present a negligible risk to public health under criteria issued by the Administrator.” 2 Legislative History, at 3939. The Act itself provides a specific alternative emission standard for coke oven batteries. Thus, a risk-based exemption for specific sources is contrary to the statutory structure and would not be approved under a deminimis test, even if the emissions impacts were trivial. EPA’s history over the past 40 years in attempting to develop a risk-based approach to regulations of toxic air emissions, and in particular the development of residual risk programs under section 112, demonstrate that these issues are far too complex and significant to be delegated to individual sources as EPA intended.]

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: N/A
Commenter Affiliation: Sierra Club, Clean Air Task Force, Earthjustice, and Natural Resources Defense Council
Document Control Number: EPA-HQ-OAR-2002-0058-3187.1
Comment Excerpt Number: 59

Comment: That is also true, as a technical matter, because health effects are based both on exposure and toxicity, and these factors vary significantly between HAPs. The California standards for the acid gases EPA seeks information on -- chlorine, HF and HCN – show that these pollutants are more toxic on a weight/volume basis than HCl (considering the respiration/inhalation pathway of exposure). And chlorine, HCN and HF are approximately 10 times more toxic than HCl for short-term exposures. Therefore, unless chlorine, HF, and HCN are always present at concentrations that are ten-fold lower than HCl, even for short durations (and EPA does not have such information), only separate health-based thresholds could ever be technically justified.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: N/A
Commenter Affiliation: Sierra Club, Clean Air Task Force, Earthjustice, and Natural Resources Defense Council

Document Control Number: EPA-HQ-OAR-2002-0058-3187.1
Comment Excerpt Number: 60

Comment: The requirement that §112(d)(4) standards must incorporate "an ample margin of safety" prohibits EPA from acting under this section where it lacks evidence on certain dimensions of health risk.

The "ample margin of safety" language in section 112(d)(4) means at the very least that any standard that is set under this authority must be sufficient to protect against significant unforeseen consequences, particularly where the Agency is aware that those consequences may occur, but simply does not have enough evidence about them. See, e.g. EDF v. EPA, 598 F.2d 62, 81 (D.C.Cir. 1978)(holding that the phrase 'ample margin of safety' in the Clean Water Act's toxic provisions required EPA to protect against as yet unidentified risks to human health, including those "which research has not yet identified."). The fact that EPA has in previous rulemakings, asserted that it was appropriate to exercise § 112(d)(4) discretion in the absence of evidence of carcinogenic risk, and on the limited understanding of the health risks it did have, [Footnote: See 75 Fed. Reg. 32,020 (citing statements made in EPA's 1998 Pulp and Paper MACT, 63 Fed. Reg. at 18,765 (April 15, 1998) and Lime Manufacturing MACT, 67 Fed. Reg. at 78,054 (Dec. 20, 2002)).] does not make that interpretation correct. The absence of evidence of risk is not sufficient to demonstrate that an "ample margin of safety" exists. In fact, EPA's prior view turns the statutory requirement, as interpreted by the D.C. Circuit, on its head. Because the 'ample margin of safety' requirement is meant to protect against risks that have not yet been identified in research , a section 112(d)(4) standard simply cannot be justified on grounds that EPA does not have sufficient evidence about the health risks posed by a HAP.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: N/A
Commenter Affiliation: Sierra Club, Clean Air Task Force, Earthjustice, and Natural Resources Defense Council
Document Control Number: EPA-HQ-OAR-2002-0058-3187.1
Comment Excerpt Number: 62

Comment: Existing RfCs for the acid gases are insufficient to form the basis for a § 112(d)(4) standard for ICIBPH emissions of these pollutants.

EPA asserts that in previous rulemakings it has relied on the RfC for HCl as the basis for establishing an alternative approach to regulating HCl or other acid gases for which it has been designated a surrogate. 75 Fed. Reg. at 32,030-32,031. EPA acted unlawfully in doing so in those rules, and it is equally incorrect here to suggest that the existing RfC is an "established health threshold" that could offer sufficient support for an alternative regulatory approach for HCl, whether as a surrogate or not. Nor can the existing RfCs for other acid gases (where they exist) be used in this way.

An inhalation RfC represents the air-related toxicity value for a noncancer health endpoint associated with exposure to an air toxic, and is expressed in weight of the toxic per volume of air (mg/m3). [Footnote: See U.S. EPA, “A Review of the Reference Dose and Reference Concentration Processes. Risk Assessment Forum, Washington, DC” (2002). EPA/630/P-02/002F. Available at: http://www.epa.gov/ncea/iris/RFD FINAL1.pdf.] The inhalation RfC provides a continuous inhalation exposure estimate (with uncertainty spanning perhaps an order of magnitude) of a daily exposure to the human population (including sensitive subgroups) that is likely to be without an appreciable risk of deleterious effects during a lifetime. The inhalation RfC considers toxic effects for both the respiratory system (a portal of entry) and effects peripheral to the respiratory system (extra-respiratory or systemic effects). An RfC can be derived from a ‘no observed adverse effect level’ (NOAEL), ‘lowest observed adverse effect level’ (LOAEL), or benchmark dose, with uncertainty factors generally applied to reflect limitations of the data used. [Footnote: See U.S. EPA, “A Review of the Reference Dose and Reference Concentration Processes. Risk Assessment Forum, Washington, DC” (2002). EPA/630/P-02/002F. Available at: http://www.epa.gov/ncea/iris/RFD FINAL1.pdf.] Reference values may also be derived for acute (?24 hours), short-term (>24 hours, up to 30 days), and subchronic (>30 days, up to approximately 10% of the life span) exposure durations, all of which are derived based on an assumption of continuous exposure throughout the duration specified. RfDs and RfCs are generally used in noncancer health assessments.

Table VI-1 summarizes U.S. EPA (via the Integrated Risk Information System, IRIS [Footnote: Available at http://www.epa.gov/ncea/iris/index.html.] and California Environmental Protection Agency (Cal EPA) toxicity values [Footnote: Available at http://www.oehha.ca.gov/air/allrels.html.] for the acid gases hydrogen chloride (HCl), chlorine (Cl2), hydrogen fluoride (HF), and hydrogen cyanide (HCN). IRIS is a human health assessment program that provides high-quality science-based human health assessments to support EPA’s regulatory activities. IRIS is prepared and maintained by the EPA’s National Center for Environmental Assessment within the Office of Research and Development. [Footnote: Animal studies can form the basis for these thresholds, as is clear from Table VI-1. To account for the fact that humans may be more or less sensitive than the test animal, a 10-fold uncertainty factor is usually applied to the NOAEL. This uncertainty factor is called the "interspecies uncertainty factor." An additional 10-fold uncertainty factor, the "intraspecies uncertainty factor," is usually applied to account for the fact that some humans may be substantially more sensitive to the effects of substances than others. Additional uncertainty factors may also be applied. If studies using human subjects are the basis of a RfC, then the interspecies uncertainty factor can be reduced to as low as 1, but generally the 10-fold intraspecies uncertainty factor is retained.] IRIS contains toxicity values for noncancer and cancer endpoints. In addition, Table VI-1 contains Cal EPA toxicity values, which are promulgated for use in California by the state’s environmental agency, but which are not necessarily endorsed or adopted (“established”) by U.S. EPA. Thus, while Cal EPA values are presented here to indicate the acid gases for which one well-regarded governmental agency has determined that enough toxicity information is available to set an exposure threshold, that fact does not mean that the Cal EPA values are “established” for the purposes of § 112(d)(4).

As noted above, the “established health threshold” must be based on a NOAEL, in order to be sufficient under §112(d)(4). A NOAEL is the highest concentration where no adverse effect is observed in the most sensitive health endpoint among all studies examined. The fact that there is a NOAEL for a set for a particular health endpoint for a pollutant does not mean that there are no other health endpoints affected by exposure to that pollutant, just that other health endpoints do not occur at the concentration seen for the NOAEL of the most sensitive endpoint. If effects are observed at all dose levels tested, then the smallest dose tested, the Lowest Observed Adverse Effect Level (LOAEL) is used to calculate the RfC. An additional uncertainty factor usually is applied in these cases, since the NOAEL, by definition, would be lower than the LOAEL had it been observed.

As table VI-1 demonstrates, however, the existing RfCs for both HCN and HCl are based on studies providing 'LOAEL values, as no appropriate studies providing NOAEL values are available. These RfCs also are "inhalation RfCs" – that is they represent the health risk and toxicity associated with the inhalation pathway of exposure only. But for these pollutants, there are other exposure pathways (the skin and eyes for example) by which health effects can occur. So, even if these RfCs were set on the basis of a NOAEL (which they are not), they would be an inadequate basis for §112(d)(4) standard setting. Additionally, no RfC is available for Cl2 at all, and HF is not among the 540 substances listed within IRIS, so no RfC is available for that acid gas. Furthermore, in evaluating the evidence that is available, for HCl and HCN, EPA states that they have "low confidence" in the RfC values. Inhalation RfCs exist only for two of the acid gases emitted by ICIBPH, HCl and HCN, and both of these RfCs reflect only studies of chronic exposures.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: N/A
Commenter Affiliation: Sierra Club, Clean Air Task Force, Earthjustice, and Natural Resources Defense Council
Document Control Number: EPA-HQ-OAR-2002-0058-3187.1
Comment Excerpt Number: 63

Comment: EPA has acknowledged that exposure to HCl does damage people's health by conceding that it causes "corrosive tissue damage." 71 Fed. Reg. 76,542. Although EPA has claimed in the past that such damage does not constitute "adverse effects" because the tissue damage "does not exceed an organism's ability to repair it" ? i.e., is not permanent or fatal, id. ? that argument was preposterous, and commenters hope that EPA no longer even entertains it. Damage to an "organism's" tissue — e.g. the lung tissue of a child — is an adverse health effect. Congress did not intend EPA to invoke § 112(d)(4) unless it was established that there would be no adverse health effects and, a fortiori, did not intend the agency to do so when it knew that there would be adverse health effects.

As noted above, in evaluating human health risk for noncancer endpoints, it is equally important to consider short-term exposures as well as long-term/chronic exposure to these emissions. Moreover, health effects depend upon both exposure and toxicity, and for acute effects, HF and HCN are more toxic on a weight/volume basis than HCl. The Cal EPA sets an acute reference exposure level (1 hour exposure) (REL) as 2.1 mg/m3 for HCl, 0.21 mg/m3 for Cl2, 0.24 mg/m3 for HF, and 0.34 mg/m3 for HCN. Therefore, Cl2, HF, and HCN are approximately 10-fold more toxic than HCl on a weight-standardized basis for short-term exposures. For these reasons, as well, unless Cl2, HF, and HCN are always present at concentrations that are at least 10-fold lower than HCl, even for short (1-hour) durations (a point on which EPA does not have information in the record for this rulemaking), only separate health-based thresholds, established for each acid gas, could ever be justified.

Respiratory effects (the endpoint of most concern for HCl, Cl2, and HF but not HCN) are likely after short-term exposures to high concentrations of acid gases. EPA asserts that it has little information on the peak short-term emissions of HCl from boilers, however. Were the existing RfCs used as the basis for a 112(d)(4) alternative standard, compliance with the health-based threshold would therefore be based on long-term average exposures. Because boilers are not run constantly, and because there are a wide variety of fuels burned (even at the same boiler), it is likely that intermittent peak exposures that greatly exceed the long-term average exposures for the (fuel-dependent) acid gases could occur. Lack of data on exactly what these intermittent peak exposures might be, however, is not sufficient reason to adapt a threshold based solely on chronic exposures.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: N/A
Commenter Affiliation: Sierra Club, Clean Air Task Force, Earthjustice, and Natural Resources Defense Council
Document Control Number: EPA-HQ-OAR-2002-0058-3187.1
Comment Excerpt Number: 64

Comment: EPA's IRIS evaluates cancer risks through a two-step process, which first evaluates whether a pollutant is carcinogenic, and then, if so further describes its toxicity. The first step uses a cancer weight-of-evidence descriptor to describe a substance's potential to cause cancer in humans, and the conditions under which the carcinogenic effects may be expressed. Under the EPA's 2005 guidelines for carcinogen risk assessment, a narrative approach is used to characterize carcinogenicity. [Footnote: U.S. EPA (2005). Guidelines for Carcinogen Risk Assessment. U.S. Environmental Protection Agency, Washington, DC, EPA/630/P-03/001F, 2005. Available at: http://cfpub.epa.gov/ncea/cfm/recordisplay.cfm?deid=116283.] Five standard weight-of-evidence descriptors (Carcinogenic to Humans, Likely to Be Carcinogenic to Humans, Suggestive Evidence of Carcinogenic Potential, Inadequate Information to Assess Carcinogenic Potential, and Not Likely to Be Carcinogenic to Humans) are used as part of the narrative.

In the second IRIS step, for pollutants found to be carcinogenic at step 1, cancer slope factors (for oral exposures) and unit risks (for inhalation exposures) are used to estimate the risk of cancer associated with exposure to a carcinogenic or even a potentially carcinogenic substance. A unit risk is defined as the upper-bound, approximating a 95% confidence limit, of excess lifetime cancer risk estimated to result from continuous exposure to an agent at a concentration 1 mg/m3 in air. The interpretation of unit risk for a substance in air would be as follows: if unit risk = 2 x 10-6 per mg/m3, one might expect, as an upper bound estimate of risk, that based on a lifetime daily exposure to 1 mg/m3 of the substance in air, up to 2 excess cancer cases may develop per 1,000,000 exposed individuals.

It is notable that none of the four acid gases examined, HCl, CL2, HF, or HCN, has undergone a complete evaluation and determination of human carcinogenic potential under the IRIS program. As described above, this absence of information does not provide evidence that there is an absence of risk. Because § 112(d)(4) requires any alternative to a MACT standard to be based on both "no adverse effects" and an "ample margin of safety," the incomplete nature of this evaluation makes a §112(d)(4) standard unavailable for these pollutants.

The California EPA, under its Office of Environmental Health Hazard Assessment (OEHHA), conducts health risk assessments of chemical contaminants found in air, including those identified as toxic air contaminants under California's Air Toxics Hot Spots Act. Assessments can include development of Cancer Potency Factors to assess the cancer risk from carcinogens in air, and development of Reference Exposure Levels (RELs) to assess noncancer health impacts. Cal EPA has set both chronic RELs and acute RELs for the four acid gases considered in this rulemaking [see Table VI-1]. These limits are not U.S. EPA limits, however, and just as for the EPA RfCs, they do not include cancer risk assessments for these pollutants.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 133

Comment: The purpose of the HBE provision of the CAA is to allow EPA to focus more stringent MACT controls on non-threshold HAPs (those that could pose some level of adverse health effects at any non-zero concentration) than HAPs with thresholds, for which the level of incremental concentration from a source could pose potential health consequences. By providing a special provision for threshold HAPs that likely pose little or no potential adverse health effects, the CAA allows EPA to consider limiting the burden on regulated sources with HAP emissions that pose little or no health hazard. Some of the HAPs targeted by the Boiler MACT, such as the acid gases, hydrogen chloride (HCl), chlorine (Cl2), hydrogen fluoride (HF) and hydrogen cyanide (HCN), as well as metals such as manganese (Mn) meet the requirements for classification as threshold pollutants. Therefore, if the associated incremental ambient concentrations of these threshold pollutants as a result of emissions from a regulated source are sufficiently low, they would qualify for alternative MACT provisions under 112(d)(4).

Section 112(d)(4) does not specify how EPA should "consider threshold levels, with an ample margin of safety" in developing alternative MACT requirements. In the Pulp and Paper MACT and in the 2004 Boiler MACT, EPA maintained that that application of this CAA section is met

if the incremental exposure concentration from subject MACT sources at a facility is less than established health effects thresholds. The “margin of safety” is built into the means by which:
* Emissions and associated exposure concentrations are characterized;
* Health effects thresholds are derived; and
* Dispersion models estimate exposure.

CAA Section 112(d)(4) does not apply to HAPs from other source categories at a facility or background concentrations, as the CAA explicitly directs EPA to address residual issues subsequent to the initial MACT setting process under CAA Section 112(f)(c).
HCl typically comprises about 80% or more of acid gas emissions from boilers, with 20% or less comprised of HF. In terms of developing Health-Based Emission Limits (HBEL), it is appropriate to consider EPA’s concept of Target Organ Specific Hazard Index (TOSHI), where the potential for health consequences for various HAPs with similar types of health effects are assumed to be additive. Toxicological studies for HCl and HF indicate that they have the same mode of action as irritant acid gases. Given that HCl and HF concentrations are simultaneously present in flue gas, it may be appropriate to consider acute and chronic effects of these two HAPs collectively in evaluating peak short term (e.g., 1-hour) and long-term (e.g., annual average) exposure concentrations. This concept could be readily incorporated by computing a toxicity-weighted emission rate of HCl that accounts for HCl and HF emissions and their corresponding health effects benchmarks.
We noted that EPA’s suggestion in the 2010 proposed rule that HF and HCN could materially contribute to health risk runs directly counter to the following statement that the agency made in the preamble to the 2004 Boiler MACT Final Rule (69 FR 55244) when it stated that its research indicated that health risks from HF and HCN emissions from boilers are considered to be insignificant.

“Facilities attempting to utilize the health-based compliance alternative for HCl will not be required to evaluate emissions of other inorganic HAP except for chlorine. We conducted an assessment of boiler emissions and determined that, of the acid gas HAP controlled by scrubbing technology, chlorine is responsible for the great majority of risk and HCl is responsible for the next largest portion of the total risk. The contributions of other HAP, including hydrogen fluoride, to the total risk were negligible. Therefore, facilities attempting to demonstrate eligibility for the health-based compliance alternative for HCl, either by conducting a lookup table analysis or by conducting a site specific compliance demonstration, must include emission rates of chlorine and HCl from their boilers. We do not expect hydrogen cyanide emissions from boilers covered under the final rule.”
If EPA has conducted new research that refutes this former finding, it is imperative that this research be brought to light.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1

Comment Excerpt Number: 136

Comment: In the proposed rulemaking, EPA concluded that the information available at this time is insufficient to establish health-based emission standards for HCl or the other acid gases. In the 2004 Boiler MACT EPA concluded that HCl was a threshold pollutant for which CAA Section 112(d)(4) should be applied and there are many other historical precedents where EPA has considered HCl a threshold pollutant. Some of those precedents include: 1) National mission Standards for Hazardous Air Pollutants: Final Standards for Hazardous Air Pollutants for Hazardous Waste Combustors (Phase I Final Replacement Standards and Phase II); Final Rule; 2) National Emission Standards For Hazardous Air Pollutants; Proposed Standards For Hazardous Air Pollutants From Chemical Recovery Combustion Sources At Kraft, Soda, Sulfite, And Stand-Alone Semichemical Pulp Mills; 3) National Emission Standards for Hazardous Air Pollutants From the Portland Cement Manufacturing Industry; Proposed Rule; 4) National Emission Standards for Hazardous Air Pollutants: Chlorine and Hydrochloric Acid Emissions From Chlorine Production.

Thus, the recent change in EPA's position appears not to be based on changes in the underlying scientific evidence since 2004 but rather a shift in policy. In this proposed rulemaking, EPA interprets section 112(d)(4) to allow additional factors beyond any established health threshold, such as cumulative and ecological effects, to be weighed in making a judgment whether to set a standard for a specific pollutant based on the threshold. This interpretation of the CAA represents a significant and unexplained departure from previous MACT rulemakings and from EPA's prior decision to adopt health based emissions limitation in the 2004 industrial boiler MACT rule. The Agency has made a 180 degree turn that is not supported by the record and not scientifically justified.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 138

Comment: HCl, other acid gases and some metal HAPs, such as Mn qualify as threshold pollutants and, therefore, they should be considered under section 112(d)(4). [SEE submitted (page 169) for a list of reference for HBEL comments.] Supporting evidence includes identification of a threshold dose below which adverse effects do not occur, lack of evidence for carcinogenicity and consideration of toxicological interactions among acid gases and potential for additive effects. In addition, demonstration of a common mode of action amongst the various HAPs would support the notion of applying a single 112(d)(4) standard for acid gases.

Table 1 summarizes threshold for acute and chronic health effects data on threshold doses for HCl, Cl_2, hydrogen cyanide (HCN), HF, and Mn. Information supporting the existence of health effects thresholds for each HAP is provided below along with a discussion of whether the HAPs have similar modes of action.

Critical Target Organ

The critical target organ for acute toxicity of HCl is the upper respiratory system (sore throat, nasal discharge), lower respiratory system (pulmonary function, cough, chest pain), and eyes. The target organ for chronic toxicity is also the respiratory system.

Mechanism of Action

On contact with moisture, HCl dissociates almost completely. The hydrogen ions combine with water to form hydronium ions ($H3O+$), which can cleave organic molecules and cause cell death. Thus, the adverse effects associated with HCl exposure are due to direct contact irritation of tissues at the portal of entry and persistent cellular injury in the affected tissue.

Evidence of Threshold

An acute threshold has been established. A chronic threshold has not been established. However, data on chronic toxicity of HCl are very limited and all studies located in the literature have used the Lowest Observed Adverse Effect Level (LOAEL) as the lowest dose in the dosing regimen. Therefore, the failure to identify a chronic threshold is not an indication that no threshold exists, but rather an indication that data on chronic effects from HCl are very limited. HCl is typically an acute exposure concern but the chronic RfC is usually limiting in exposure assessments. However, controlling short-term peak exposures naturally has the dual benefit of also reducing long-term exposures. In addition to the general lack of toxicological studies suggesting that HCl could be a potential carcinogen (see below), the listing of health thresholds for HCl by the Environmental Protection Agency (EPA), Agency for Toxic Substance Disease Registry (ATSDR), California EPA, and the World Health Organization in the public domain has established that HCl is a threshold pollutant.

Evidence of Carcinogenicity

No pre-neoplastic or neoplastic nasal lesions were observed in a 128-week inhalation study with SD male rats at 10 ppm HCl gas. No evidence of treatment related carcinogenicity was observed in other animal studies performed by inhalation, oral or dermal administration. In humans, no association between HCl exposure and tumor incidence has been observed.

Cumulative Exposure

There is little evidence that the general public is exposed routinely to measurable quantities of gaseous chlorine and/or HCl. Even the HCl produced during the combustion of fossil fuels or the incineration of solid waste apparently lasts too short a time in the un-reacted state to pose a significant health risk (IPCS, 1982). However, HCl does affect the same target organ system (respiratory system) as hydrogen fluoride (HF) and, therefore, it is possible that the effects of HCl and HF could be additive.

Critical Target Organ

The critical target organ for the acute toxicity of Cl2 is the upper respiratory system (transient respiratory irritation), lower respiratory system (slight alterations in pulmonary function tests), and the eyes. The target organ for chronic toxicity is also the respiratory system.

Mechanism of Action

Cl_2 is a strong oxidizer that hydrolyzes in water forming HCl and hypochlorous acid. Cl_2 gas has been shown to be 33 times more potent as a sensory irritant in mice than HCl (Barrow et al. 1977), The assumption is that products of the reaction of Cl_2 with water are able to interact with functional groups in components from cells in the respiratory epithelium. At low concentrations, only sensory receptors are affected, triggering only changes in respiratory dynamics, but higher concentrations produce frank tissue damage due to disruption of cellular components (ATSDR, 2007).

Evidence of Threshold

The effects of acute-exposure to Cl_2 have been well characterized in humans and animals. Collectively, the results suggest that brief exposures to concentrations of Cl_2 less than 0.5 ppm do not cause sensory irritation or significant alterations in pulmonary function tests, but exposure to 1 ppm or greater can induce transient respiratory and eye irritation and slight alterations in pulmonary function tests (Anglen 1981; D'Alessandro et al. 1996; Rotman et al. 1983; Schins et al. 2000; Shusterman et al. 1998, 2003). There is no information regarding chronic-duration exposure of the general population to chlorine because this type of exposure occurs only in occupational settings. There are few studies of chronically exposed workers that were not also subjected to acute episodes of high exposure or "gassing" incidents. However, a chronic threshold based on nasal lesions has been established in monkeys (Klonne et al. 1987).

Evidence of Carcinogenicity

No studies on the carcinogenic effects of Cl_2 in humans and only a few animal studies were located in the literature. All of the animal carcinogenicity studies listed on the Chemical Carcinogenesis Research Information System were negative and no positive studies were listed on the Carcinogenic Potency Project at http://potency.berkeley.edu/chemicalsummary.html. Co-carcinogenic properties (i.e., some studies suggest that Cl_2 can promote the carcinogenicity of other compounds) of Cl_2 in animals have been examined, but the results are mixed, with one study resulting in cancer in a single mouse and another study causing a 40% decrease in the number of skin cancers in initiated mice. Study results on genotoxicity of Cl_2 have also been mixed. Neither, the EPA, the International Agency for Research on Cancer (IARC), or the Department of Health and Human Services (DHHS) have classified Cl_2 gas as to its carcinogenicity. Although EPA has not developed a formal evaluation of the potential for Cl_2 carcinogenicity, the evaluation by the International Agency for Research on Cancer stated that there was inadequate evidence for carcinogenicity in humans or experimental animals and thus concluded that Cl_2 is not classifiable as to its carcinogenicity to humans. Other rules (e.g., Final Standards for Hazardous Air Pollutants for Hazardous Waste Combustors (Phase I Final Replacement Standards and Phase II); Final Rule; 2) National Emission Standards For Hazardous Air Pollutants) have evaluated Cl_2 only with regard to non-cancer effects. In the absence of specific scientific evidence to the contrary, it has been EPA's policy to classify non-carcinogenic effects as threshold effects.

Cumulative Exposure

There is little evidence that the general public is exposed routinely to measurable quantities of gaseous Cl_2. However, Cl_2 does affect the same acute target organ system (respiratory system) as HCl and hydrogen fluoride (HF) and the same chronic target organ system (respiratory system) as HCl, Therefore, it is possible that the acute effects of Cl2, HCl and HF could be additive and the chronic effects of Cl2 and HCl could also potentially be additive.

1. Hydrogen Cyanide (HCN)

Critical Target Organ

The Central Nervous System (CNS) is the target organ for the acute health effects associated with HCN. The critical target organ for the chronic health effects of HCN is also the CNS, but long-term exposure can also affect thyroid function (CalEPA, 2008b).

Mechanism of Action

The mode of action of HCN toxicity is cytochrome oxidase inhibition, which prevents cellular utilization of oxygen. The cyanide ion blocks oxidative respiration, causing failure of oxygen usage with tissue hypoxia leading to metabolic acidosis.

Evidence of Threshold

An acute threshold has been established. A chronic threshold in humans has not been established. Data on chronic toxicity of HCN in humans (and animals) is very limited. However, a subacute inhalation NOAEL for HCN has been established in rabbits (CalEPA, 2008b). In addition to the lack of evidence that HCN is a potential carcinogen (see below), the listing of health thresholds for HCN by California EPA (CalEPA, 2008b) and many other organizations (e.g., Agency for Toxic Substance Registry [ATSDR], World Health Organization [WHO], National Institute of Public Health and the Environment, Bilthoven (The Netherlands), etc.) in the public domain has established HCN as a threshold pollutant.

Evidence of Carcinogenicity

Out of 20 mutagenicity studies summarized on the Chemical Carcinogenesis Research Information System (CCRIS) for sodium cyanide, there was not a single positive result (CCRIS, 2010). Therefore, available data indicate that HCN does not have mutagenic properties and is not considered to be a carcinogen. Free CN is not classifiable as to human carcinogenicity (IRIS, 2010).

Cumulative Exposure

HCN has a completely different mechanism of action than the other two acid gases on which comments have been requested (i.e., HCl and HF) and affects a different target organ system. While several studies indicate that chronic exposure of workers to low concentrations of cyanide can cause respiratory, cardiovascular, and thyroid effects, the acute effect on the CNS system occurs at lower concentrations than those at which the portal of entry (respiratory) effects occur. Because HCN has a different mode of action than HCl and HF, it is not a candidate for a limit that addresses the combined effects of multiple acid gases.

2. Hydrogen Fluoride (HF)

Critical Target Organ

The critical target organ for acute health effects of HF is the upper respiratory system (irritation), with symptoms such as coughing, choking, and chills, followed by pulmonary edema, which may occur with cough, chest tightness, rales, and cyanosis after an asymptomatic period of one to two days (CalEPA, 2008a). The critical chronic target organs include bone and teeth (skeletal/dental fluorosis), as well as the upper respiratory system (pulmonary hemorrhage) (CalEPA, 2008b).

Mechanism of Action The acute respiratory effects of HF are the result of dehydration and corrosion of tissues mediated by free hydrogen ions (CalEPA, 2008a). The respiratory system is also listed as one of the critical target organs for chronic toxic effects of HF; however, respiratory effects result from higher exposure levels than required for fluorosis (Hodge and Smith, 1977). Presumably, direct contact irritation of tissues at the portal of entry and persistent cellular injury in the affected tissue are responsible for the chronic respiratory effects of HF. In addition, the dissociated fluoride ion is also capable of complexing certain bivalent cations, primarily calcium and magnesium, which interferes with calcium metabolism and causes cell destruction (CalEPA, 2008b) and fluorosis upon chronic exposure. Skeletal fluorosis is considered to be the critical target organ for chronic exposure since this effect is seen at lower concentrations than the respiratory system effects.

Evidence of Threshold

Both acute and chronic threshold doses have been established. In addition, since lower doses of fluoride have a beneficial or nutritional effect, a threshold type of response for adverse effects is clearly expected (CalEPA, 2008b). In addition to the general lack of evidence that HF is a carcinogen in humans (see discussion below), the listing of health thresholds for HF by California EPA (CalEPA, 2008b) and many other organizations (e.g., Agency for Toxic Substance Registry [ATSDR], World Health Organization [WHO], etc.) in the public domain has established HF as a threshold pollutant.

Carcinogenicity

Several authors have suggested the potential mutagenicity of HF or sodium fluoride, although EPA and National Research Council have concluded that the mutagenicity of HF in man has not been demonstrated (EPA, 1998). According to the National Toxicology Program, "the preponderance of evidence" from laboratory in vitro (i.e., cell culture) studies indicate that fluoride is a mutagenic compound in laboratory studies. Some substances that are shown to be mutagens in laboratory studies, are also carcinogens. In some cases, “the overall significance of the in vitro fluoride transformation data are subject to question" (NRC, 1993) because the cells used in some of the laboratory studies are unusually sensitive to the induction of transformation. In addition, the concentrations of fluoride causing mutagenic damage in the in vitro studies is higher than the concentrations found in human blood. More importantly, no specific epidemiological evidence is available for evaluation of the potential carcinogenicity of HF or other fluoride compounds in humans. Increased rates of cancer have been reported in workers in several industries involving exposure to mixtures containing fluorides, but fluoride could not be specifically implicated as the cause of the cancer in any of these studies (EPA, 1998). The potential carcinogenic potential of fluorides in drinking water has also been investigated. The International Agency for Research on Cancer (IARC) concluded that when differences in demographics, degree of industrialization, and other social factors are accounted for, the studies provide no evidence that an increase in the level fluorides in drinking water is associated with an increase in cancer mortality (EPA, 1998). Therefore, there is a lack of evidence to suggest that HF or other fluoride compounds are carcinogenic.

3. Manganese (MN)

Critical Acute Target Organ

Mn toxicity has been reported through occupational (e.g. welder) and dietary overexposure and is evidenced primarily in the Central Nervous System, although lung, cardiac, liver, reproductive and fetal toxicity have been noted. The CNS is considered the critical target organ for the chronic toxicity of Mn (Crossgrove and Zheng, 2004). No information on acute toxicity of Mn could be located in the open scientific literature.

Mechanism of Action

Mn neurotoxicity results from an accumulation of the metal in brain tissue and results in a progressive disorder of the extrapyramidal system which is similar to Parkinson's disease. In order for Mn to distribute from blood into brain tissue, it must cross either the blood–brain barrier (BBB) or the blood–cerebrospinal fluid barrier (BCB). Brain import, with no evidence of export, would lead to brain Mn accumulation and neurotoxicity. The mechanism for the neurodegenerative damage specific to select brain regions is not clearly understood. Disturbances in iron homeostasis and the valence state of Mn have been implicated as key factors in contributing to Mn toxicity (Crossgrove and Zheng, 2004).

Evidence of a Threshold

Lower doses of Mn have a beneficial or nutritional effects, therefore, a threshold type of response for adverse effects is clearly expected. There is debate about where the threshold for Manganese falls, but several studies in the last two decades provide for determination of No Observed Adverse Effect Levels (NOAELs) for chronic neurological effects in workers. In addition to the lack of evidence that Mn is a carcinogen (see discussion below), the listing of health thresholds for Manganese by EPA, California EPA (CalEPA, 2008b) and the Agency for Toxic Substance Registry (ATSDR) in the public domain has established Manganese as a threshold pollutant.

Evidence of Carcinogenicity

Mn is listed in IRIS as Classification D (not classifiable as to human carcinogenicity) (IRIS, 2010). Although there are some mixed results, there are little data to suggest that inorganic Mn is carcinogenic.

1. Evidence for Thresholds

Hydrogen Chloride (HCl)

Based on the limited negative carcinogenicity data, and on knowledge of how chlorine reacts in the body, its likely mechanism of action, and its consideration as a threshold pollutant in numerous other rulemakings, HCl is presumptively considered to be a threshold pollutant.

Chlorine (Cl2)

Based on the thresholds established for Cl2, the lack of evidence for carcinogenicity, it's likely mechanism of action, and it's consideration as a threshold pollutant in numerous other rulemakings, Cl2 is presumptively considered to be a threshold pollutant.

Hydrogen Cyanide (HCN)

Based on the thresholds established for HCN, the lack of evidence for carcinogenity, and knowledge of how HCN reacts in the body, HCN is considered to be a threshold pollutant.

Hydrogen Fluoride (HF)

Based on the thresholds that have been established and lack of reliable data suggesting that HF is carcinogenic, HF is presumptively considered to be a threshold pollutant.

Manganese (Mn)

Lower doses of Mn have a beneficial or nutritional effects, therefore, a threshold type of response for adverse effects is clearly expected. In addition to the lack of evidence that Mn is a carcinogen (see discussion below), the listing of health thresholds for Manganese by EPA, California EPA (CalEPA, 2008b) and the Agency for Toxic Substance Registry (ATSDR) in the public domain has established Manganese as a threshold pollutant.

Proposed Toxicity Factors and Margins of Safety

Hydrogen Chloride (HCl)

It is proposed that the California EPA (CalEPA) acute Reference Exposure Level (REL) be established as the acute threshold dose and that the EPA RfC be established as the chronic threshold dose. The human studies on which the California acute REL is based were done with asthmatics, which represent a sensitive human subpopulation. Also, the chronic EPA RfC has a cumulative uncertainty factor of 300 (10 for extrapolation from a LOAEL to a NOAEL, 3 for interspecies variability, and 10 for intraspecies variability) built into it. Therefore, both the acute and chronic threshold values recommended for HCl provide an ample margin of safety for use in establishing emission standards under CAA112(d)(4).

Chlorine (Cl2)

It is proposed that the Agency for Toxic Substances and Disease Registry (ATSDR) acute Minimal Risk Levels (MRL) be established as the acute threshold dose. The acute no-observed-adverse-effect level (NOAEL) of 0.5 ppm was adjusted to account for continuous exposure (0.5 ppm x 8 hours/24 hours = 0.2 ppm). Although sensitive individuals were tested in some of the studies, an uncertainty factor of 3 was used to account for sensitive populations to arrive at the acute-duration inhalation MRL of 0.07 ppm (0.2 ppm/3). It is also proposed that the ATSDR chronic MRL be established as the chronic threshold dose. An uncertainty factor of 30 (3 for extrapolation from animals to humans with dosimetric adjustment and 10 for human variability) was applied to the lower 95% confidence limit predicted exposure concentration associated with a 10% extra risk to arrive at the chronic-duration inhalation MRL of 0.00005 ppm for Cl2. Therefore, both the acute and chronic threshold values recommended for Cl2 provide an ample margin of safety for use in establishing emission standards under CAA 112(d)(4).

Hydrogen Cyanide (HCN)

It is proposed that the California EPA (CalEPA) acute Reference Exposure Level (REL) be established as the acute threshold dose and that the EPA RfC be established as the chronic threshold dose. The California acute REL has a cumulative uncertainty factor of 100 (10 for interspecies variability and 10 for intraspecies variability) built into it. In addition, the acute studies were done on primates, which represent the species most similar to man, thereby reducing uncertainty regarding toxic response. Also, the chronic EPA RfC has a cumulative uncertainty factor of 1000. A factor of 10 is used for sensitive human subpopulations, a factor of 10 is used for the lack of a NOAEL, and partial factors of 3 each are used for deficiencies in the database (lack of chronic and multigenerational reproduction studies) and for less than chronic duration. Therefore, both the acute and chronic threshold values recommended for HCN provide an ample margin of safety for use in establishing emission standards under CAA112(d)(4).

Hydrogen Fluoride (HF)

It is proposed that the CalEPA acute and chronic RELs be established as threshold doses for HF. Both the acute and chronic California RELs for HF incorporate a cumulative uncertainty factor of 10 to account for variability in human responses (intraspecies variability) to inhalation exposure to HF. While this safety factor is not as large as some, both threshold values are judged to provide an ample margin of safety for use in establishing emission standards under CAA112(d)(4) since the studies were conducted in human populations, thereby eliminating much of the uncertainty regarding toxic responses. The chronic REL in particular is judged to be amply conservative because the human population consisted of fertilizer plant workers who were no doubt exposed to many other chemicals simultaneously.

Manganese (Mn)

No acute toxicity criteria for Mn were located in the open scientific literature. It is proposed that the EPA RfC be established as the chronic threshold dose. The chronic EPA RfC has a cumulative uncertainty factor of 1000. This uncertainty factor reflects 10 to protect sensitive individuals, 10 for use of a LOAEL, and 10 for database limitations reflecting both the less-than-chronic periods of exposure and the lack of developmental data, as well as potential but unquantified differences in the toxicity of different forms of Mn. Therefore, the chronic threshold value recommended for Mn provides an ample margin of safety for use in establishing emission standards under CAA112(d).

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 139

Comment: Both acute and chronic exposure to HCl, Cl2 and HF affect the respiratory system and the pollutants cause respiratory irritation by similar mechanisms of action (direct contact irritation of tissues at the portal of entry and persistent cellular injury in the affected tissue). However, the critical effect on which the chronic toxicity criterion for HF is based is skeletal fluorosis, which occurs at lower doses than the reported respiratory effects (Hodge and Smith, 1977). Therefore, it is recommended that a combined acute HBEL for HCl, Cl2, and HF and a combined chronic HBEL for HCl and Cl2 be established. However, a separate chronic 112(d)(4) HBEL for HF is recommended.

While chronic exposure of workers to low concentrations of cyanide can cause respiratory symptoms, effects on the CNS system occur at lower concentrations than those at which the portal of entry (respiratory) effects occur. In addition, HCN has a completely different mechanism of action than HCl and HF. Therefore, HCN is not a good candidate for inclusion if a combined acid gas standard is derived. Therefore, establishment of a single acute 112(d)(4) HBEL for HCN is recommended. Although the critical target organ for Mn is the CNS, Mn has a completely different mechanism of action from HCN. Since Mn has a different mechanism of action from HCN and affects a different target organ than HCl and HF, establishment of a separate chronic 112(d)(4) HBEL for Mn is indicated as well.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Melvin E. Keener
Commenter Affiliation: Coalition for Responsible Waste Incineration (CRWI)
Document Control Number: EPA-HQ-OAR-2002-0058-2824.1
Comment Excerpt Number: 15

Comment: An ample margin of safety has been demonstrated.

When setting a health-based limit, the Agency is required to ensure that the level will be protective of human health, with an ample margin of safety. Traditionally, that level has been the RfC which, as the Agency knows, contains multiple levels of added safety. For example, the RfC for HCI is 20 ug/m3, 30 times lower than the NOAEL. By setting a site-specific standard at a hazardous index (ratio of the exposure at the fence line to the reference concentration) to 1.0, EPA will have demonstrated an ample margin of safety.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-2702.1
Comment Excerpt Number: 200

Comment: Implementation of HBCAs.
Some of the HAPs targeted by the Boiler MACT, such as hydrogen chloride (HCl), chlorine gas (Cl2), hydrogen fluoride (HF) and hydrogen cyanide (HCN) meet the requirements for classification as threshold pollutants. Therefore, if the associated incremental ambient concentrations of these threshold pollutants as a result of emissions from a regulated source are sufficiently low, they would qualify for an HBCA under Section112(d)(4).

CIBO believes that the Boiler MACT should include HBCAs that take the form of a limited number of alternative HAP emissions limits based upon facility specific emissions of HCl, Cl2, HF and HCN and modeling against references concentrations provided by EPA using a health index.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-2702.1
Comment Excerpt Number: 202

Comment: Hydrogen Cyanide Emissions are Insignificant And Should Not Factor Into an HBCA.
As discussed above, CIBO strongly believes that an HBCA needs to be established to allow units covered by the Boiler MACT to comply with the rule's requirements and timetables. However, in setting this HBCA, CIBO believes that hydrogen cyanide (HCN) should not be included, because HCN emissions make insignificant contributions to any relevant health risk.

EPA has long recognized that the chief acid gas HAPs emitted from most industrial facilities are chiefly HCl and HF. In its 2004 response to comments on the prior Boiler MACT rule, EPA stated: "We conducted an assessment of boiler emissions and determined that . . . the contributions of other HAP [aside from HCl and chlorine] . . . to the total risk were negligible." 69 FR 55218-44 (Sept. 13, 2004). Thus, at that time, EPA commented that it did not expect HCN emissions from boilers to be covered under that rule. Id.

A review of TRI 2008 data (excluding EGUs, chemical plants, and metal mining) indicates that this conclusion has not changed over the last few years, since only 0.3% of HAP gas emissions are HCN. The Proposed Rule reaches similar results. The percentages EPA has provided for HAP emissions in the Proposed Rule – which do not include HCN emissions – sum to 99%, indicating that HAP emissions are insignificant. 75 FR 32011. Because HCN emissions are insignificant in assessing health based risk, they should not factor into HBCA compliance.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: J. Michael Geers
Commenter Affiliation: Duke Energy
Document Control Number: EPA-HQ-OAR-2002-0058-2765.1
Comment Excerpt Number: 9

Comment: As a practical matter, 112(d)(4) applies to non-carcinogenic HAPs [Footnote: Almost without exception, EPA assumes a linear, no-threshold dose-effect relationship for HAPs that are classified as carcinogens.] for which EPA has established a health threshold such as a reference concentration ("RfC") or a reference dose ("RfD"). EPA defines a reference concentration in its IRIS database as "[a]n estimate (with uncertainty spanning perhaps an order of magnitude) of a continuous inhalation exposure to the human population (including sensitive subgroups) that is likely to be without an appreciable risk of deleterious effects during a lifetime." [Footnote: The definition for a reference dose is essentially the same except it focuses on exposures by pathways other than inhalation.] Thus, human exposures to a HAP at levels below its RfC are considered "safe" particularly given the uncertainty factor that EPA includes as part of its derivation of a RfC. Congress' inclusion of 112(d)(4) in the 1990 CAA Amendments indicates an intent to retain the health endpoint of the original 112 -- protection of public health with an ample margin of safety. If the emissions of a given HAP from all sources in a source category are at a level where public health is protected with an ample margin of safety, then there is no practical need for or benefit from further regulation.

Duke Energy believes that in many cases, HAP emissions from industrial boilers will pose minimal risk to human health or the environment. Incorporating this option into the final rule would provide significant cost savings by foregoing the requirement for add-on controls on industrial boilers whose emissions do not exceed health benchmarks. At the same time, this mechanism would ensure that industrial boilers whose emissions do exceed these benchmarks are controlled. As a result, Duke Energy believes EPA can and should set health-base standards under 112(d)(4) when facts support its use.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Russ A. Wozniak
Commenter Affiliation: Dow Chemical Company
Document Control Number: EPA-HQ-OAR-2002-0058-2632.1
Comment Excerpt Number: 67

Comment: On Page 32031 of the preamble, EPA concludes, "we do not have sufficient information at this time to establish what the health-based emission standards would be for HCl or other acid gases." EPA invites public comment on EPA's information and conclusion. EPA could rely on information such as the Texas Commission on Environmental Quality (TCEQ) Effects Screening Levels (ESL's) to establish concentration-based limits for each of these pollutants. ESL's are based on data concerning health effects, odor/nuisance potential, and effects on vegetation, thus satisfying the criteria for both health concerns and also impact on the surrounding environment. These values are also periodically reviewed and updated by a rigorous process defined by TCEQ. Dow believes that these levels are set at a level where no observable effects occur, with an ample margin of safety.

[See submittal for TCEQ's ESL's for the air contaminants of concern.]

Note: TCEQ's annual average value for HCl of 7.5 micrograms per cubic meter is less than EPA's chronic reference concentration of 20 micrograms per cubic meter noted on Page 32031 of the preamble.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Russ A. Wozniak
Commenter Affiliation: Dow Chemical Company
Document Control Number: EPA-HQ-OAR-2002-0058-2632.1
Comment Excerpt Number: 68

Comment: Dow comments that permitted emissions of HCl are more than 10 times higher than of the other individual HAP's from our coal-fueled boiler. Thus, using HCl as a surrogate for the other HAP's still remains as a reasonable option even though their ESL's are slightly lower than that of HCl.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Sheila C. Holman
Commenter Affiliation: North Carolina Department of Environment and Natural Resources
Document Control Number: EPA-HQ-OAR-2002-0058-2798.1
Comment Excerpt Number: 2

Comment: As part of our toxics permitting process, NC DAQ routinely applies a health risk-based methodology similar to what EPA is requesting, including:
Establishing health risk-based concentration thresholds for toxic air pollutants, known as

Acceptable Ambient Levels (AALs), which represent a level "below the concentration that would produce adverse health effects in sensitive subgroups of the general population." For example, under NC air toxics rules, HCl is considered an acute irritant with an AAL of 0.7 milligrams per cubic meter (mg/m3) for 1-hour exposure. Similarly, hydrogen fluoride (HF) has an AAL of 0.25 mg/m3 for 1-hour exposure, but also an AAL of 0.03 mg/m3 for 24-hour exposure.

Compiling facility-specific toxic air pollutant emissions from each permitted source,

Collecting emission release parameters and coordinates for each emission source
Obtaining facility geospatial data and building downwash parameters (tier heights and footprint coordinates), and

Performing dispersion. modeling, using EPA approved procedures, to determine air pollutant concentrations at the property boundaries.

Using the EPA Human Exposure Model, NC DAQ conducted a statewide risk assessment screening study of 1800 facilities to evaluate cancer and non-cancer health risks from combustion sources and boiler emissions.2
[Footnote 1: http://daq.state.nc.o/toxics/aaldisc.pdf
[Footnote 2: Series of 8 presentations given to the NC Air Quality Commission from October 2005 to September 2007.]

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Richard Krock
Commenter Affiliation: The Vinyl Institute
Document Control Number: EPA-HQ-OAR-2002-0058-2944.1

Comment Excerpt Number: 6

Comment: EPA should develop MACT controls on non-threshold HAPs (those that could pose some level of adverse health effects at any non-zero concentration) and HAPs with thresholds, for which the level of incremental concentration from a source could pose potential health consequences. Some of the HAPs targeted by the Boiler MACT, such as the acidic gases, hydrogen chloride (HCl), hydrogen fluoride (HF) and hydrogen cyanide (HCN), and metals such as manganese (Mn) meet the requirements for classification as threshold pollutants. Until such risk characterized health assessment is completed for these acidic gas pollutants, EPA should consider limiting the burden on regulated sources by providing a special provision for threshold HAPs that pose little or no potential adverse health effects.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Bill Perdue
Commenter Affiliation: American Home Furnishings Alliance
Document Control Number: EPA-HQ-OAR-2002-0058-2692.1
Comment Excerpt Number: 8

Comment: In the preamble to the 2004 Boiler MACT, the EPA correctly made the case that hydrogen chloride (HCl) and manganese (Mn) are threshold pollutants subject to consideration for a Health Based Compliance Alternative (HBCA) under Section 112(d)(4). The HBCA allows the EPA to minimize the probability that a source might have to incur significant regulatory burden and cost to install and operate a pollution control device that provides minimal or no demonstrated health benefit, and it specifically applies to pollutants with established thresholds below which no adverse health effects occur. HCl and Mn are boiler HAPs with established thresholds or evidence that effects are very limited. Considerable research has demonstrated that there is no evidence of carcinogenicity for either substance.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Traylor Champion
Commenter Affiliation: Georgia-Pacific LLC
Document Control Number: EPA-HQ-OAR-2002-0058-2745.1
Comment Excerpt Number: 10

Comment: Acid gases and manganese are threshold pollutants and not carcinogenic.
In the original 2004 Boiler MACT rule, EPA determined that hydrogen chloride (HCl) and manganese (Mn), are threshold pollutants. There is no scientific data to suggest that HCl is carcinogenic and very little data that Mn is carcinogenic. The science for this determination has not changed since 2004 and thus EPA’s conclusion remains valid for this proposed rule.

The other major acid gases, hydrogen fluoride (HF) and HCN are also threshold pollutants as described fully in the AF&PA comments. There is also a lack of evidence that HF, other fluoride compounds or HCN are carcinogenic.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Jerry Osheka
Commenter Affiliation: PPG Industries
Document Control Number: EPA-HQ-OAR-2002-0058-2938.1
Comment Excerpt Number: 10

Comment: In the newly proposed Industrial Boiler MACT, EPA acknowledges its authority under § 112(d)(4) to establish a health-based emissions limitation for threshold pollutants in lieu of a MACT emissions limitation. However, the Agency proposes not to establish any health based emissions limitations "[g]iven the limitations of the currently available information (i.e., the HAP mix where boilers are located, and the cumulative health impacts from co-located sources), the environmental effects of HCl, and the significant co-benefits of setting a conventional MACT standard for HCl."4 Nevertheless, EPA asks for comment on a wide range of issues related to the justification for setting health based emissions limitations and the method by which they should be set.

Ample scientific information supports a determination that HCl, hydrogen fluoride, hydrogen cyanide, and manganese are threshold pollutants and, thus, are eligible to be regulated under § 112(d)(4). In addition, the Agency has the technical tools and significant factual support for establishing health based emissions limitations for these HAPs that would provide the requisite ample margin of safety to health and the environment. Thus, health based emissions limitations are fully justified on scientific and technical grounds. EPA should set health based emission limitations for HAP acid gases and, like in the 2004 rule, a health based emissions limit for manganese, which should be implemented in conjunction with a Total Select Metal ("TSM") standard (where the TSM standard would be an alternative to the PM surrogate, and where a "TSM less manganese" option would be provided when a source elects to comply with the health based compliance alternative for manganese).

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Michael Hutcheson
Commenter Affiliation: Ameren Services
Document Control Number: EPA-HQ-OAR-2002-0058-2803.1
Comment Excerpt Number: 19

Comment: Ameren supports the risk assessments conducted on behalf of the electric utility industry by the Electric Power Research Institute (EPRI) and submitted to US EPA on risk associated with HCL emissions from Utility boilers. Based on the data in that assessment, Ameren believes it is unlikely that an analysis of HCL emissions from industrial, commercial or institutional boilers will show any significant health effects from HCL emissions.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Ted Michaels
Commenter Affiliation: Energy Recovery Council
Document Control Number: EPA-HQ-OAR-2002-0058-2831.1
Comment Excerpt Number: 20

Comment: Ample scientific information supports a determination that HCl, hydrogen fluoride, hydrogen cyanide, and manganese are threshold pollutants and, thus, are eligible to be regulated under Section 112(d)(4). In addition, the Agency has the technical tools and significant factual support for establishing health based emissions limitations for these HAPs that would provide the requisite ample margin of safety to health and the environment. Thus, health based emissions limitations are fully justified on scientific and technical grounds. EPA should set health based emission limitations for HAP acid gases and, like in the 2004 rule, a health based emissions limit for manganese, which should be implemented in conjunction with a Total Select Metal ("TSM") standard (where the TSM standard would be an alternative to the PM surrogate, and where a "TSM less manganese" option would be provided when a source elects to comply with the health based compliance alternative for manganese).

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 110

Comment: Finally, EPA states that it does "not have sufficient information at this time to establish what the health-based emission standards would be for HCl." [75 Fed. Reg. at 134.] As such, EPA cannot demonstrate that the technology driven standard will achieve a degree of reduction in emissions of HCl greater than what could be achieved under a health-based standard. There is no question that technology driven standards under section 112(d) must achieve the maximum degree of reduction in HAP emissions, but EPA has not demonstrated that, putting aside the alleged criteria pollutant co-benefits, its proposed MACT standard for HCl will achieve the maximum reduction in emissions of HCl.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 111

Comment: ACC Supports the Inclusion of Work Practices. Instead of prescribing numeric HAP emissions limitations on boilers burning clean gas fuels (the "Gas 1" subcategory), EPA proposes to adopt work practices requiring an annual tune up of units that have a heat input capacity of less than 10MMBtu/h, and all units that combust natural gas and refinery gas (Gas 1 and Metal Process Furnaces Subcategories). For units larger than 100 mmBtu/hr, EPA explains that "the capital costs estimated for installing controls on these boilers and process heaters to comply with MACT limits for the five HAP groups is over $14 billion."[75 Fed. Reg. at 32025.] EPA further explains that:

[T]he need to employ the same emission control system as needed for the other fuel types would have the negative benefit of providing a disincentive for switching to gas as a control technique (and a pollution prevention technique) for boilers and process heaters in the other fuel subcategories. In addition, emission limits on gas-fired boilers and process heaters may have the negative benefit of providing an incentive for a facility to switch from gas (considered a "clean" fuel) to a "dirtier" but cheaper fuel (i.e., coal). It would be inconsistent with the emissions reductions goals of the CAA, and of section 112 in particular, to adopt requirements that would result in an overall increase in HAP emissions.[Id.]

Response: We appreciate the input from the commenter. EPA is not finalizing limits for units firing natural gas, refinery gas, and other Gas 1 fuels. See preamble for rationale for selecting a work practice for these units.

HBCA: Co-Benefits of Controlling HCl and Mn

Commenter Name: N/A
Commenter Affiliation: Sierra Club, Clean Air Task Force, Earthjustice, and Natural Resources Defense Council
Document Control Number: EPA-HQ-OAR-2002-0058-3187.1
Comment Excerpt Number: 65

Comment: Section 112(d)(4)'s Requirement to Set Any Health-Based Standards With "An Ample Margin of Safety" Requires Evaluation of Synergistic Health Effects, and From all HAP Emissions From the Industrial Facility, not the Boiler Alone.

EPA seeks comment on questions about whether there would be additive effects if individual section 112(d)(4) standards are established for each acid gas, and if so, how that effect could be simulated. 75 Fed. Reg. 32,032. The agency asserts that "[i]ndividual acid gas standards under section 112(d)(4) would likely be established using the hazard quotient (HQ) approach, under which we would develop the ratio of the maximum ambient level to the chronic threshold. However, this approach would not by itself account for potential toxicologic interactions. Since all of the acid gases are respiratory irritants, one way to account for potential toxicologic interactions of these pollutants would be the use of the hazard index (HI) approach, as described in EPA's "Guideline for the Health Risk Assessment of Chemical Mixtures." [Footnote: US EPA 2000. Supplementary Guidance for Conducting Health Risk Assessment of Chemical Mixtures. U.S. Environmental Protection Agency, Washington DC. EPA/630/R-00/002. Available at: http://www.epa.gov/nceawww1/pdfs/chem_mix/chem_mix_08_2001.pdf. This guidance replaced previous U.S. EPA "Guidelines for the Health Risk Assessment of Chemical Mixtures," 51 Fed. Reg. 34,014 (Sept. 24, 1986), available at: http://cfpub.epa.gov/ncea/cfm/recordisplay.cfm?deid=22567.] Id. EPA requests comment on that approach, and on whether there are any other approaches to address such additive issues.

We assert that EPA's assumption that it can properly "address additive issues" in this way is not justified. Based on its Hazard Index approach, [Footnote: 75 Fed. Reg. at 32032 referencing "Guidance for the Health Risk Assessment of Chemical Mixtures" (no citation given), but see previous note.] and in the absence of studies explicitly addressing the toxicity of mixtures of HCl with other respiratory irritants, EPA is taking the position that if the different acid gases affect health through the same health endpoint, they can be assumed to interact additively. However, this fundamental assumption is not correct. At least one of the acid gases emitted by boilers, HCN, is a known neurotoxin. Its health effects therefore must not be considered additive with the health effects of other acid gases for which the health endpoint is different. Additionally, although Table VI-1 shows the effects for the target organs and pathways studied, there are other pathways of exposure affecting other target organs, and the combined effects are not additive just as the effects of HCN are not additive with HCl. For these reasons, the Agency should not assume an additive effects among these HAP.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: N/A
Commenter Affiliation: Sierra Club, Clean Air Task Force, Earthjustice, and Natural Resources Defense Council
Document Control Number: EPA-HQ-OAR-2002-0058-3187.1
Comment Excerpt Number: 66

Comment: As acknowledged by the Agency, 75 Fed. Reg. 32,032, industrial and commercial boilers are often located at sites with significant additional sources of HAPs and other pollutants. These pollutants can have synergistic effects with the HAPs emitted by the ICIBPH. For example among the pollutants that may be emitted by other emissions units onsite is particulate matter (PM), including PM in the respirable size range, PM10 (PM that are less than or equal to 10 micrometers [?m] in aerodynamic diameter). Health effects associated with PM are stronger for fine (PM2.5) and ultrafine particles (PM0.1) because they can penetrate deeper into the airways of the respiratory tract and can reach the alveoli in which 50% are retained in the lung parenchyma. Under atmospheric conditions volatile HAPs that are emitted by boilers can condense onto the surface of these PM, allowing the HAPs to travel along with the particles. Such particles can serve as “carriers” to bring the adhered HAPS deep within the lung, where the HAPS can interact with the respiratory system directly or be leached off of the particle surface and become available systemically. Other HAPS and criteria pollutants may also be present on PM, including transition metals, ions (sulfate, nitrate), organic compound, quinoid stable radicals of carbonaceous material, minerals, reactive gases, and materials of biologic origin. [Footnote: See, e.g., U.S. EPA, “Review of the National Ambient Air Quality Standards for Particulate Matter: Policy Assessment of Scientific and Technical Information. OAQPS Staff Paper” (2006). EPA-452/R05-005a., available at: http://www.epa.gov/ttnnaaqs/standards/pm/data/pmstaffpaper_20051221.pdf (discussing these effects).]

PM are just one of the additional pollutants that will be emitted from boilers; the fact that boilers can be located among a wide variety of industrial facilities makes predicting and assessing all possible mixtures of HCl and other emitted air pollutants difficult, if not impossible. Because the statute requires standard setting with an “ample margin of safety” when §112(d)(4) is invoked, as discussed above, these synergies make this kind of standard setting practicably impossible to do lawfully for this industrial category.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: N/A
Commenter Affiliation: Sierra Club, Clean Air Task Force, Earthjustice, and Natural Resources Defense Council
Document Control Number: EPA-HQ-OAR-2002-0058-3187.1
Comment Excerpt Number: 67

Comment: Section 112(d)(4)’s Requirement to Set Any Health-Based Standards With “An Ample Margin of Safety” Requires Evaluation of Health Effects Beyond the Fenceline. Environmental Justice Concerns Mitigate Against Anything Other than MACT-based Standards for this Reason.

EPA also requests comment on whether HAP emissions from neighboring facilities must be evaluated in setting §112(d)(4) standards, and, if so, what the geographic scope of such consideration should be. 75 Fed. Reg. 32,032. EPA properly notes that consideration of emissions from nearby facilities is a far more difficult task to undertake in national standard setting than consideration of facility-wide emissions, since it requires information on all potential HAP emissions near all of the locations with the almost 15,500 boilers affected by the rule. The Agency asks, however, whether such standards could be based on “ ‘average’ or ‘high- end’ ambient levels of respiratory irritants seen in recent monitoring data or modeled estimates, since site-specific data might not be available on all respiratory irritants.” 75 Fed. Reg. 32,032. EPA further solicits comment on whether or not it can, and how it should “appropriately “simulate all reasonable facility/exposure situations (e.g., using worst-case facility emissions coupled with worst-case population proximity, average emissions and population, or 90th percentile emissions and population).” Id.

This question by the Agency in fact illustrates why MACT standard setting is and should be the default requirement in the 1990 Clean Air Act, rather than “health-based” standard-setting under section 112(d)(4). The fact that industrial sources of air toxics are often located in areas with other sources of HAPs, including point sources, area sources, and mobile sources, is a major (although not the only) reason that the former, exclusively health-based scheme for standard setting, was so unworkable. Not only are the physical interrelationships between the HAPs synergistic, making the health effects very difficult to predict, but each situation will involve HAPs with different characteristics with respect to spatial distributions, and health endpoints. Defining the geographic scope will not be possible on a nationwide basis for this reason. At the very least, a “high end” ambient level of respiratory irritants as seen in central site monitors or as modeled will have to be used in order to even begin to satisfy the Act’s requirement of an “ample margin of safety.”

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: N/A
Commenter Affiliation: Sierra Club, Clean Air Task Force, Earthjustice, and Natural Resources Defense Council
Document Control Number: EPA-HQ-OAR-2002-0058-3187.1
Comment Excerpt Number: 69

Comment: EPA notes that it “considered that setting conventional MACT standards for HCl as well as PM (as a surrogate for metals including manganese) would result in significant reductions in emissions of other pollutants, most notably SO2, non-condensable PM, and other non-HAP acid gases (e.g., hydrogen bromide) and would likely also result in additional reductions in emissions of mercury and other HAP metals (e.g., selenium). The additional reductions of SO2 alone attributable to the proposed MACT standard for HCl are estimated to be 340,000 tons per year in the third year following promulgation of the proposed HCl standard. These are substantial reductions with substantial public health benefits. Although MACT standards may directly address only HAPs, not criteria pollutants, Congress did recognize, in the legislative history to section 112(d)(4), that MACT standards would have the collateral benefit of controlling criteria pollutants as well and viewed this as an important benefit of the air toxics program.” 75 Fed. Reg. 32,032. EPA asserts that even where there is an “established health threshold” for a HAP, the Agency “may consider such benefits as a factor in determining whether to exercise its discretion under section 112(d)(4).” Id.

As a threshold matter, as commenters describe above, there is no “established health threshold” for HCl or for any of the acid gases emitted by ICIBPH, such that a §112(d)(4) standard could be set with an “ample margin of safety.” But even if there were, the Agency would be required to consider – indeed to compare -- the environmental and other impacts and benefits of a MACT standard and a section 112(d)(4) alternative. EPA knows this – the Agency points out, 75 Fed.

Reg. at 32,031, that “employing a §112(d)(4) standard rather than a conventional MACT standard ‘shall not result in adverse environmental effect which would otherwise be reduced or eliminated.’ ” Id. (emphasis added) (quoting S. Rep. No. 228, 101st Cong., 1st Sess. (1989) at 171). It is impossible to make this assessment without evaluating the collateral benefits of a MACT standard. And , as described in the recently finalized cement kiln MACT rule, [Footnote: Available at http://www.epa.gov/ttn/oarpg/t1/fr notices/portland cement fr 080910.pdf.] setting technology-based standards for HCl will result in significant reductions in the emissions of other pollutants, including SO2, mercury, and PM. These reductions will provide enormous health and environmental benefits, that would not be experienced if section 112(d)(4) standards had been finalized.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 129

Comment: EPA asserts in the proposed rule that its decision not to propose HBELs “is not contrary to EPA’s prior decisions where we found it appropriate to exercise the discretion to invoke the authority in section 112(d)(4) for HCl, since the circumstances in this case differ from previous considerations.” Draft at 140. In contrast to “other source categories for which EPA has exercised its authority under section 112(d)(4),” EPA explains that boilers and process heaters are more likely to be co-located with other HAP sources and are often located in heavily populated urban areas where many other HAP sources exist. Id. at 140-141. The Agency concludes that, “These factors make an analysis of the health impact of emissions from these sources on the exposed population significantly more complex than for many other source categories, and therefore make it more difficult to establish an ample margin of safety.” Id. at 141.

These assertions are astonishing in that they fail to reflect the fact that the industrial boiler source category is one of the few categories where EPA has previously “found it appropriate to exercise the discretion to invoke the authority in section 112(d)(4).” As a result, EPA has already drawn conclusions as to how to deal with possible co-location with other HAP sources and how to appropriately consider HAP emissions from other nearby sources. These are not issues of first impression generally or in the specific context of industrial boilers and process heaters. The questions have been asked and answered in the context of notice and comment rulemaking for the industrial boiler and process heater source category.

Thus, EPA is mistaken in asserting that its decision not to propose HBELs is “not contrary to EPA’s prior decisions.” The decision not to propose HBELs is flatly inconsistent with EPA’s prior determination that HBELs are appropriate and justified for the industrial boiler and process heater source category.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 130

Comment: The co-benefits of collateral non-HAP emissions reductions cannot be used to justify a decision not to adopt HBELs.

EPA explains in the proposal that "it considered the fact that setting conventional MACT standards for HCl as well as PM (as a surrogate for metals including manganese) would result in significant reductions in emissions of other pollutants, most notably SO2, non-condensable PM, and other non-HAP acid gases (e.g., hydrogen bromide) and would likely also result in additional reductions in emissions of mercury and other HAP metals (e.g., selenium)." Draft at 139. The Agency notes in particular that its belief that the rule will result in the reduction of up to 340,000 tons per year of SO2, which it characterizes as "substantial reductions with substantial health benefits." Id. EPA asserts that Congress acknowledged the possibility that MACT standards would result in collateral non-HAP emissions reductions and, therefore, that "the Agency may consider such benefits as a factor in determining whether to exercise its discretion under section 112(d)(4)." Id. at 140.

EPA is mistaken. Consideration of non-HAP collateral emissions reductions is impermissible in setting MACT standards. Section 112(d)(2) provides an express list of factors that EPA may consider in setting § 112(d) standards – including "the cost of achieving such emission reduction, and any non-air quality health and environmental impacts and energy requirements." This list does not allow consideration of non-HAP air quality benefits, such as the co-benefits of reducing PM2.5 emissions. This restriction is an unambiguous command that EPA should not consider non-HAP air quality benefits in setting standards under § 112(d).

More fundamentally, the CAA clearly distinguishes regulation of HAPs from criteria pollutants. Section 112 "prohibits the addition of any criteria pollutant to 'the list' of HAPs, with a single exception for certain precursor pollutants not relevant to this case. This prohibition extends of necessity not only to rules that literally list a criteria pollutant as a HAP but also to any rule that in effect treats a criteria pollutant as a HAP." National Lime Ass'n v. U.S. EPA, 233 F.3d 625, 638 (D.C. Cir. 2000).

By basing its rejection of the health-based approach for Boiler MACT on the co-benefits of criteria pollutant reduction, EPA is "in effect" unlawfully treating a criteria pollutant as a HAP. EPA's action here is not the simple use of a criteria pollutant as a surrogate for a HAP, which courts have upheld as long as EPA proves the scientific underpinning of the surrogate relationship. Id. Rather, EPA argues directly that it is the reduction in criteria pollutant emissions that causes it to reject the health-based approach. This EPA cannot do. Moreover, criteria pollutants from boilers are strictly regulated elsewhere under the Clean Air Act through New Source Performance Standards and other provisions of the Act.

EPA's sole support for its "collateral benefits" theory is legislative history -- the Senate Report that accompanied Senate Bill 1630 in 1989. But the D.C. Circuit rejected precisely the same argument in National Lime. In that case, EPA supported its argument regarding particulate matter as a surrogate for HAP metals by referring to the same Senate Report discussed above. The court rejected EPA's argument, noting that the Senate Report referred to an earlier version of the statute that was ultimately not enacted, and hence was irrelevant:

The final statute, by contrast, unqualifiedly prohibits listing a criteria pollutant as a HAP, that is, regardless of the reason. Because the comment in the Senate Report regarding PM and metals was made before the blanket prohibition upon regulating PM as a HAP was added to the statute, the report is irrelevant to our construction of 7412(b)(2) as enacted.
National Lime at 638. Similarly here, EPA cannot use the language of a Senate Report that did not reflect the language of the statute as enacted to support its co-benefits theory and rejection of the health-based approach.

Moreover, even if it were relevant, the language in the Senate Report cited by EPA appears to address only area-source GACT standards under Section 112(d)(5), and therefore is not relevant to interpretation of MACT standards under Section 112(d)(2) or the health- based alternative under Section 112(d)(4). And, in the final analysis, "it is the statute, and not the Committee Report, which is the authoritative expression of the law." City of Chicago v. Env. Defense Fund, 511 U.S. 328, 337 (1994). Here, the statute clearly provides that MACT standards may address only HAPs, not criteria pollutants. See National Lime Ass'n at 638.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 131

Comment: Consideration of non-HAP air quality benefits under § 112(d)(4) would be unreasonable. National Ambient Air Quality Standards ("NAAQS") are in place for all relevant pollutants, including ozone, SO2, and PM. A MACT standard is a very imprecise tool for helping to attain and maintain such NAAQS because it imposes across-the-board requirements in circumstances where tailored solutions are needed. Each area has its own unique mix of sources and it own particular needs in terms of what reductions are needed and where such reductions should be achieved. SIP-based air quality programs provide the needed flexibility to design a program that effectively addresses local air quality needs. MACT standards are an unreasonably blunt instrument for dealing with non-HAP air quality issues.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 132

Comment: Emissions of SO_2 from unit burning biomass are very low when compared to other fuels. The AP-42 emission factor for wood combustion is 0.025 lb/mmBTU and AF&PA's experience with biomass units is that SO_2 emissions are routinely much lower than this emission factor. NCASI also has completed research (NCASI Technical Bulletin 640, Sulfur Capture in Combination Bark Boilers, and Special Report 09-02, Sulfur Capture in Combination Bark Boilers – An Update) that demonstrates that even when sulfur containing fuels are burned with biomass, a significant portion of sulfur is captured by the alkaline wood ash. These 2 documents are available to NCASI members and can be made available to EPA staff upon request. Thus, even if EPA could consider co-benefits of non-HAP reductions in developing standards under § 112, the nominal co-benefits of reducing SO_2 emissions from biomass units would not outweigh the other advantages of establishing a health- based emissions limitation for HCl.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 134

Comment: As noted, the language of CAA Section 112(d)(f) does not express any intent that emissions from other types of sources at a facility or background concentrations should be considered in a cumulative fashion with emissions from permitted source. Evaluation of the acid gas impacts from all regulated boilers at a facility will, in most cases, address virtually all of the irritant gas hazard. With the possible exception of some types of chemical production and metallurgical facilities, nearly all of the industrial emissions of HCl (and other acid gases) at industrial facilities are associated with boilers. As such, computing an acid gas TOSHI associated with boiler emissions only under CAA 112(d)(4) represents the acid gas risk for the entire facility. Once acid gases are emitted from a stack, they have a short atmospheric half-life due to high solubility and reactivity, and as such, concentrations decrease rapidly with distance from a source. Thus, it would be a very unusual circumstance if impacts from multiple facilities would overlap in a cumulative layer cake fashion. This is confirmed by ambient measurement studies in source-rich urban areas, which have shown that HCl concentrations are very low, typically less than 5% of the 20 µg/m3 Reference Concentration (RfC). In coastal areas, most of the airborne HCl is attributable to the contribution of air-sea interaction. Natural coastal deposition of HCl is also reflected in data from EPA's National Acid Deposition Network, which indicates that there is no spatial correlation between deposition and major combustion sources.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 141

Comment: Among the reasons cited by EPA for not proposing the HBEL for HCl in the 2010 Boiler MACT rule is the belief that impacts from other sources at the same facility or nearby facilities may need to be considered in evaluating risk. As noted above, the language of CAA Section 112(d)(4) indicates that only the potential threshold health effects from the MACT source should be considered. Furthermore combined risk sources from various MACT categories should be considered under the residual risk program, after MACT standards have been promulgated and implemented. However, even if an HBEL analysis were to consider these cumulative exposures, the effect would be minimal because the evidence indicates that the potential incremental risk added as a result of overlapping plumes is very small.

The chief acid gas HAPs emitted from most industrial boilers are chiefly HCl (since most elemental chlorine in fuel is converted to HCl during combustion) and HF. A review of TRI 2008 data (excluding EGUs, chemical plants, and metal mining) indicates that 77.3% of acid HAP gas emissions are HCl, 22.4 % are HF and only 0.3% are HCN. As noted, the threshold effects of acid gases are dissimilar to other HAPs and, therefore, these can be considered separately from other HAPs using EPA's TOSHI concept. At most types of industrial facilities that have substantial emissions of acid gases, solid fuel boilers subject to the boiler MACT (or other MACT such as the Hazardous Waste Combustor MACT) are the only significant source of these emissions. Because it is unlikely that there would be a substantial contribution of acid gas HAP emissions that are not regulated under the boiler MACT at most facilities, it should not generally be necessary to consider non boiler MACT sources in establishing HBELs.

Another consideration potentially affecting HBEL development is whether boiler MACT source impacts from nearby facilities overlap. Even if this were applicable under CAA 112(d)(4), dispersion modeling shows that maximum impact short-term and annual average concentrations of non-reactive pollutants associated with boiler emissions generally occur within 1 km and fall off rapidly with distance. This limits the range at which appreciable concentrations of these gases are transported. Because acid gases are highly soluble, react with ammonia the ambient air, and are rapidly deposited through wet and dry deposition, the range of ground-level concentrations is much more limited than for non-reactive pollutants. Therefore, unless there are boilers at an immediately adjacent facility, it is highly unlikely that impacts would overlap to the extent that it would materially affect the HBEL.

There is no evidence that background concentrations of HCl are at appreciable levels from a public health perspective. A limited number of ambient measurement studies have shown that ambient concentrations, even in highly urbanized areas, are very low. A long-term measurement study of ambient acid gas concentrations in New York City (Bari et al 2003) indicates an average of about 0.5 µg/m3, which is only 2.5% of the chronic RfC (Reference Concentration). Thus,

there is little basis for adjusting the HBEL to adjust for background concentrations of acid HAP gases.
A study of HCl emissions and impacts from utility boilers (Harkov 1999) concludes that, even in the vicinity of major sources of HCl, ambient concentrations are very low. This report states: "In the atmosphere, HCl is fairly short-lived…since it is very soluble and reacts readily with ammonia (NH3) or alkaline cations such as Ca or K to form chloride salts. Therefore, even though the mass of HCl emitted may be substantial, the actual impacts of these emissions may not be significant. For example, data from the National Atmospheric Deposition Program (NADP 1998) National Trends Network deposition monitoring network over the years indicates that chloride ion deposition is strongly influenced by sea salts, rather than simply point sources of HCl emissions… EPA did not identify exceedances of any HCl health-based standards in the health risk studies reported in the Utility HAP Report (EPA 1998a)."
The conclusion is that evaluation of non-boiler MACT, multiple facility and background do not need to be considered in establishing HBELs for acid HAP gases.
Another assertion in the proposed Boiler MACT rule is that control of HCl emissions from solid fuel boilers will reduce acidic deposition. A map of chloride deposition in 1997 (from Harkov, 1999) illustrates that there is no correlation between chloride deposition and distance from coal fired power plants in the Ohio Valley or industrial areas in the Midwest but is instead is related to the influence of sea salt, especially in the Pacific Northwest, New England and Southern Atlantic and Gulf coasts. Thus, there is no indication that HCl deposition from major point source emissions contribute materially to chloride deposition or acidification. [See submittal for map of chloride deposition.]

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Melvin E. Keener
Commenter Affiliation: Coalition for Responsible Waste Incineration (CRWI)
Document Control Number: EPA-HQ-OAR-2002-0058-2824.1
Comment Excerpt Number: 17

Comment: EPA should only consider the affected source and not include all sources at the facility or surrounding facilities.

CRWI believes that Congress expected EPA to consider the effect of co-located facilities during the § 112(f) residual risk program so that, by the time EPA has promulgated residual risk standards for all source categories, risks from co-located sources will be adequately addressed. As'indicated by Senator Durenberger's comments during the debate of the Clean Air Act Amendments of 1990, EPA should consider residual risk in the context of different HAP source. Categories that might be co-located at the same site. See Brick MACT proposal, 67 FR 47894, 47905, fn. 5 (July 22, 2002) citing Senate Debate on Conference Report (October 27, 1990) reprinted in "A Legislative History of the Clean Air Act Amendments of 1990," Comm. Print S. Rrt. 103-38 (1993) ("Legis. Hist.") at 868.

Under § 112(d), however, the targets of regulation are new or existing sources of hazardous air pollutants within the specified source category (or subcategories) under consideration — not all sources at the site. EPA sets these standards by considering the emission levels achieved by the best performers in their respective category or subcategory. CAA § 112(d)(3).

Congress carried this concept into § 112(d)(4) as well. The legislative history explains that the focus of the Agency's authority under section 112(d)(4) is preventing risks from the sources themselves. As the Committee on Environment and Public Works explained, where some sources do emit more than the threshold amount, the Administrator is authorized by section 112(d)(4) to use the no observable effects level of NOEL (again with an ample margin of safety) as the emission limitation in lieu of more stringent "best technology" requirements. Following this scenario, only those sources in the category which present a risk to public health (those emitting in amounts greater than the threshold) would be required to install controls, even though the general policy is "maximum achievable technology" everywhere.

S. Rep. No 228, 101st Cong. Sess. 175-176 (1989) (emphasis supplied).

In addition, there is no prior EPA precedent for considering co-located facilities from a different source category during the same § 112 rulemaking.' In the Benzene NESHAP, where EPA noted that it should consider "effects due to co-location of facilities" id. at 54 FR 38045, EPA was only considering sources from the same category. HOwever, in that rule "co-location" was not all sources at the site. Instead it was all sources within the source category. As explained in a section of the preamble labeled "Application of Policy to Benzene Source Categories" EPA explained that it derived the regulatory level on "model plants" to represent the sources being regulated. For Benzene Storage. Vessels, EPA said, "Where two or more of the model plants used for the analysis might occur at one site (e.g., both a producer and a consumer of benzene), the risks were calculated from their total emissions." Id. at 38050-01. Consequently, EPA examined the effects of co-location only from the "model plants" EPA was evaluating — and not from emissions sources outside the source category it was evaluating.

In summary, consideration of sources outside the source category is antithetical to the concept of MACT standards for individual source categories. CRWI suggests that EPA's limit the §112(d)(4) standard to only those sources within the source category. Thus, a decision to limit the provision's focus_to each unit impacted is supported by Congressional intent and, prior precedent.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Melvin E. Keener
Commenter Affiliation: Coalition for Responsible Waste Incineration (CRWI)
Document Control Number: EPA-HQ-OAR-2002-0058-2824.1
Comment Excerpt Number: 18

Comment: SO2 control is, overestimated.

EPA should not rely on the additional SO2 reductions that will be achieved by HCI control as a public health or environmental benefit to prevent them from establishing a health-based standard. While the Senate mentioned in its report that EPA may consider the benefits that MACT standards might have on nohHAP pollutants, CRWI notes that Congress placed the §112(d)(4) authority in the statute, not just its deliberations, thereby expressing a stronger intent for the Agency to consider and implement.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: David A. Buff
Commenter Affiliation: Golder Associates Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2801.1
Comment Excerpt Number: 44

Comment: The statute makes clear that criteria pollutant co-benefits associated with the proposed MACT standards may not be considered in deciding whether to establish §112(d)(4) health based emissions limitations. Also, EPA has failed to explain why the health based emissions limitations it established in the 2004 Industrial Boiler MACT and the justification provided for those limitations should now be reversed. The preamble to the newly proposed rule sets out a number of questions that might be relevant in deciding whether to establish health based emissions limitations, but merely raising questions is not a sufficient basis for reversing prior determinations adopted through notice and comment rulemaking. Thus, EPA's proposal not to set health based emissions limitations runs counter to the law and is based on an inadequate explanation of why the Agency proposes to depart from its prior approach.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-2702.1
Comment Excerpt Number: 201

Comment: EPA Should Not Consider Impacts From Multiple Sources For HCl.
CIBO feels strongly that EPA should not consider other sources' emissions when considering impacts from a single source's emissions. One of the reasons EPA has given for not proposing the HBCA for HCl in the Proposed Rule is the belief that impacts from other sources at the same facility or even nearby facilities, may need to be considered. This is an incorrect belief, as Section 112(d)(4) indicates that only the potential threshold effects from the MACT source itself be considered. Moreover, residual risk approaches have not extended beyond the single MACT source.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Douglas A. McWilliams
Commenter Affiliation: American Municipal Power
Document Control Number: EPA-HQ-OAR-2002-0058-2808.1
Comment Excerpt Number: 4

Comment: Providing regulatory flexibility by means of HBELs will not cause any harm to human health or the environment. When the first Boiler MACT rule was promulgated in 2004, it included HBELs for HC1 and manganese. Under both of those standards, a site-specific risk assessment was required to prove that emissions from the site were low enough to protect human health, with an ample margin of safety. Actual emissions testing of all affected emission points was required to verify the emission rates used in the risk assessment. All relevant site parameters were to be recorded in the site's Title V operating permit to provide assurance over time that public health would be adequately protected. See 69 Fed. Reg. at 55227-28. Painesville and Orrville have conducted this testing and their permits reflect the parameters that Ohio EPA and U.S. EPA have determined are adequately protective of human health with a margin of safety. EPA's general speculation about co-located HAP sources and urban HAP loadings are not relevant to these municipal utilities and should not be used to arbitrarily deny health-based relief already approved on a site-specific basis.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Douglas A. McWilliams
Commenter Affiliation: American Municipal Power
Document Control Number: EPA-HQ-OAR-2002-0058-2808.1
Comment Excerpt Number: 7

Comment: The proposed Rule attempts to justify its adoption of technology-based standards over HBELs by citing the co-benefits of collateral non-HAP emission reduction. Specifically, it explains that "it considered the fact that setting conventional MACT standards for HC1 as well as PM (as a surrogate for metals including manganese) would result in significant reductions in emissions of other pollutants, most notably SO2, non-condensable PM, and other non-HAP acid gases (e.g., hydrogen bromide) and would likely also result in additional reductions in emissions of mercury and other HAP metals (e.g., selenium)." 75 Fed. Reg. at 32032. The Agency notes in particular its belief that the rule will result in the reduction of up to 340,000 tons per year of SO2, which it characterizes as "substantial reductions with substantial health benefits." Id. EPA asserts that Congress acknowledged the possibility that MACT standards would result in collateral non-HAP emissions reductions and, therefore, that "the Agency may consider such benefits as a factor in determining whether to exercise its discretion under section 112(d)(4)." Id. EPA is mistaken. Consideration of non-HAP collateral emissions reductions is impermissible in setting MACT standards. Section 112(d)(2) provides an express list of factors that EPA may consider in setting section 112(d) standards. That list includes "the cost of achieving such emission reduction, and any non-air quality health and environmental impacts and energy requirements." (Emphasis added.) It does not include consideration of non-HAP air quality benefits, such as the co-benefits EPA cites above. This restriction is an unambiguous command that EPA not consider non-HAP air quality benefits in setting standards under section 112(d).

Standards (,NAAQS") are in place for all relevant pollutants, including ozone, SO2, and PM. A MAC f standard is a very imprecise tool for helping to attain and maintain such NAAQS because it imposes across-the-board national requirements in circumstances where tailored solutions are needed. itch area has its own unique mix of sources and its own particular needs in terms of what reductions are required and where such reductions should be achieved. SIP-based air quality programs provide the flexibility Congress intended to design a program that effectively addresses local air quality needs. MACT standards are an unreasonably blunt instrument that was neither designed nor intended to deal with non-HAP air quality issues.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Susan J. Miller
Commenter Affiliation: Brick Industry Association
Document Control Number: EPA-HQ-OAR-2002-0058-2716.1
Comment Excerpt Number: 8

Comment: BIA is distressed by EPA's growing and illegal dependence on non-HAP benefits to justify a HAP regulation. Congress clearly developed separate sections of the CAA to deal with different pollutants, based on the specific impacts of those pollutants. For example, only HAPs have anything like a "floor" that must be established before a cost and other impacts based final level is established. While we can commend EPA's attempts to provide overall strategy for air quality for an industry, these "good intentions" cannot be used to push through environmental limitations that violate the requirements of the CAA.

For example, EPA has repeatedly argued that it cannot consider costs in the MACT floor. However, EPA then turns around and uses monetized benefits of non-HAP emission reductions as a justification or benefit of their decisions. If costs do not belong in the floor, neither do negative costs (i.e., benefits).

Response: preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Susan J. Miller
Commenter Affiliation: Brick Industry Association
Document Control Number: EPA-HQ-OAR-2002-0058-2716.1
Comment Excerpt Number: 9

Comment: In establishing the emission level that is considered MACT, the CAA clearly and in plain language instructs EPA to NOT consider other air quality benefits, only non-air quality benefits [Section 112(d)(2), emphasis added]:

Emission standards promulgated under this subsection and applicable to new or existing sources of hazardous air pollutants shall require the maximum degree of reduction in emissions of the hazardous air pollutants subject to this sections...where the Administrator, taking into consideration the costs of achieving such emission reduction, and any non air-quality health and environmental impacts and energy requirements, determines is achievable....

This clearly demonstrates that EPA cannot consider other air quality benefits when justifying a MACT, nor can they be considered when identifying the MACT floor. Clearly, Congress recognized that there were other sections of the CAA that could, and should, be used to regulate non-HAP air contaminants. These other programs have totally separate approaches for setting the standards and for considering impacts.

Response: preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Douglas A. McWilliams
Commenter Affiliation: American Municipal Power
Document Control Number: EPA-HQ-OAR-2002-0058-2808.1
Comment Excerpt Number: 9

Comment: Even taking EPA's concerns regarding co-located sources and proximity to other significant HAP sources in heavily populated urban areas at face value, they do not apply to small municipal utilities. Rather, municipal utilities operate boilers and generators as their exclusive HAP source and do not operate co-located HAP sources within their fence line. Also, AMP members are located in small towns and cities, not in heavily populated urban areas where other HAP sources are common. The Agency concludes that "[t]hese factors make an analysis of the health impact of emissions from these sources on the exposed population significantly more complex than for many other source categories, and therefore make it more difficult to establish an ample margin of safety." 75 Fed. Reg. at 32032. To the contrary, these factors support using an HBEL for a small municipal utilities subcategory.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Douglas A. McWilliams
Commenter Affiliation: American Municipal Power
Document Control Number: EPA-HQ-OAR-2002-0058-2808.1
Comment Excerpt Number: 11

Comment: That is particularly true with respect to HBELs since municipal utilities do not evoke the two key reservations cited by EPA in the Proposed Rule: the risk of co-located HAP sources and proximity to urban HAP generation. Unlike certain other sources, the only HAP source at small municipal utilities are the boilers that will be subject to regulation by this rule. Also, municipal utilities are located in town centers where zoning precludes a concentration of sources emitting pollutants that may contribute to a synergistic effect in the environment. By their very nature, municipal utilities are located in small towns - far from urban centers where concentration of HAP emissions is a potential concern. Given this unique profile, municipal utilities do not present the obstacles to HBELs that were the subject of EPA's request for comment in the

Proposed Rule preamble. Establishing a subcategory for small municipal utilities thus presents an appropriate and defensible way to narrowly apply HBELs even if EPA determines they are not viable on a broader scale.

Response: See preamble for response to final decision on Health Based Compliance Alternative. See response to comment EPA-HQ-OAR-2002-0058-2795.1, excerpt 1 for additional subcategory for small municipal utilities or subcategorizing according to sector.

Commenter Name: Russ A. Wozniak
Commenter Affiliation: Dow Chemical Company
Document Control Number: EPA-HQ-OAR-2002-0058-2632.1
Comment Excerpt Number: 70

Comment: EPA requests comment on whether to consider the affected sources (boilers) by themselves or whether to consider all HAP emissions at the facility when developing a 112(d)(4) standard. Dow comments that EPA's rule should include all sources of the same HAP when requiring an owner/operator to conduct dispersion modeling studies to demonstrate compliance with a HBCA limit. In other words, the owner/operator should include all sources of HCl, Cl2, HF, and HCN at the major source when making a modeling demonstration under section 112(d)(4). This type of approach will ensure that the off-site impact of these emissions is less than thresholds of concern. However, EPA should not require an evaluation of all other HAPs at the site though since they are regulated under many different source categories and they will be reviewed in due time in accordance with the residual risk evaluations.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Russ A. Wozniak
Commenter Affiliation: Dow Chemical Company
Document Control Number: EPA-HQ-OAR-2002-0058-2632.1
Comment Excerpt Number: 71

Comment: EPA requests comment on whether HAP emissions from nearby neighboring facilities should be considered and what the geographic scope of such consideration should be. These decisions should be made on a case-by-case basis. EPA should issue guidance on when and how to aggregate HAP emissions from multiple sites in close proximity with different owners.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Russ A. Wozniak
Commenter Affiliation: Dow Chemical Company
Document Control Number: EPA-HQ-OAR-2002-0058-2632.1
Comment Excerpt Number: 72

Comment: EPA also mentions in the preamble that setting conventional MACT standards for HCl as well as PM (as a surrogate for metals including manganese) would result in significant emission reductions in emissions of other pollutants, most notably SO2, and would likely also result in additional reductions of other criteria air pollutants. EPA believes that this proposed MACT rule will have the collateral benefit of controlling criteria pollutants as well and views this as an important benefit of the air toxics program. EPA's assumptions are incorrect in some cases. By establishing specific emission limits for certain pollutants, such as CO, for coal fired boilers, regulated entities will be required to install CO emission reduction catalyst in some cases. The use of this catalyst will result in an increase in NOx and also will increase CO_2 emissions from these sources. Likewise, for another subcategory, owner/operators will also be required to operate sources that use "Other Process Gas" in an inefficient manner to approach the proposed limit of 1 ppmv CO, thus again increasing NOx and CO_2 emissions from these sources.

Response:

Commenter Name: Shelley Schneider
Commenter Affiliation: Nebraska Department of Environmental Quality
Document Control Number: EPA-HQ-OAR-2002-0058-2820.1
Comment Excerpt Number: 2

Comment: We agree with EPA that the co-benefits of reducing criteria pollutants by promulgating a conventional MACT standard far outweigh the indefinite results of implementing a health-based standard with limited data on its cumulative impacts.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: James C. Jackson

Commenter Affiliation: Boise, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2855.1
Comment Excerpt Number: 4

Comment: For Boise, the health-based emissions limitation alternative is a critical tool that would be used to assure adequate protection of human health and the environment while avoiding unnecessary costly wet scrubbers to control acid gases which are emitted at very low levels from our biomass boilers due the inherent low chloride content of our predominant biomass fuels. Avoiding such wet scrubbing controls arguably would have a positive environmental impact due to the fact that substantial resources (e.g., water use, electric energy) are consumed and more indirect greenhouse gases from purchased electricity are emitted by an additional wet scrubbing process. While EPA is legally not allowed to consider sulfur dioxide emission reduction co-benefits in this rulemaking that might occur from wet scrubbing, in Boise's case, such co-benefits would be insignificant due to the fact that there is very little sulfur in the biomass fuels we predominantly burn and thus very low sulfur dioxide emissions.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Christian Richter
Commenter Affiliation: American Foundry Society
Document Control Number: EPA-HQ-OAR-2002-0058-2766.2
Comment Excerpt Number: 4

Comment: The CAA also makes clear that criteria pollutant co-benefits associated with the proposed MACT standards may not be considered in deciding whether to establish health-based emissions limitations. In addition, EPA has failed to explain why the health-based emissions limitations it established in the 2004 Industrial Boiler MACT were not proposed and why the justification provided for those limitations should now be reversed.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Edward E. Quick
Commenter Affiliation: Celanese International Corp
Document Control Number: EPA-HQ-OAR-2002-0058-2840.1
Comment Excerpt Number: 5

Comment: Multi-source, multi-pollutant and multi-media analyses have not prevented implementation of air quality standards in the past. Given that the proposed standards (without HBELs) will potentially lead to the closure of several manufacturing facilities within the US, EPA should exercise their discretionary authority to provide the regulated industry an option to comply with emission limits or alternative health-based emission limits. HBELs are not only a consistent precedent for establishing National Ambient Air Quality Standards (NAAQS) but also enables industry to focus on reductions that will result in the greatest environmental benefit.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Jerry Osheka
Commenter Affiliation: PPG Industries
Document Control Number: EPA-HQ-OAR-2002-0058-2938.1
Comment Excerpt Number: 11

Comment: In response the request for comments on whether EPA should “consider the affected sources (boilers) by themselves, or whether we should consider all HAP emissions at the facility when developing a 112(d)(4) standard” (FR 32,032), PPG believes that EPA should consider affected sources individually. Few significant sources of HCl exist other than large utility boilers that are part of the industrial boilers and process heaters regulated under this proposed rule. Those utility boilers, in most cases, will be regulated by both the Utility MACT and the Clean Air Transport Rule, providing the EPA with ample opportunity to effect improvements to public health by regulating acid gas emissions from those units. EPA should not disproportionately burden industrial sources with the combined effects of their own emissions plus those of other sources by considering emissions from other affected sources in the area.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Traylor Champion
Commenter Affiliation: Georgia-Pacific LLC
Document Control Number: EPA-HQ-OAR-2002-0058-2745.1
Comment Excerpt Number: 12

Comment: An HCl HBCA should be implemented for biomass boilers
Notwithstanding Georgia-Pacific’s basic position that EPA can and should establish an “across the board” HBCA for HCl, we believe that EPA has the authority under section 112(d)(4) to establish a Risk-Based Standard for HCl specifically for inherently low SO2 emitting biomass boilers. EPA recently decided in the Portland Cement Manufacturing Industry MACT not to establish a risk-based standard for HCl partly on the basis of the secondary benefits associated with controlling SO2 emissions. While GP and EPA may disagree on the legality of considering the secondary benefits of controlling criteria pollutants while establishing a NESHAP; there should be no disagreement that the secondary SO2 control benefits associated burning biomass are very small and the added costs of controls is not justified.
Emissions of SO2 from units burning biomass are very low when compared to other fuels. AP-42 emission factors for wood residual combustion is 0.025 #/mmBTU1 and GP’s experience with our biomass units is that SO2 emissions are routinely much lower then this emission factor. NCASI has also completed research (NCASI Technical Bulletin 640) that demonstrates that even

when sulfur containing fuels are burned with biomass, a significant portion of sulfur is captured by the alkaline wood ash. Therefore since controlling HCl does not result in a concurrent SO2 reduction, SO2 reduction should not be used as a basis for justifying HCL controls.
[Footnote 1: By comparison, the AP-42 emission factor for coal-fired units is about 2 lb/MMBtu.]

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Paul N. Cicio
Commenter Affiliation: Industrial Energy Consumers of America
Document Control Number: EPA-HQ-OAR-2002-0058-2752.1
Comment Excerpt Number: 14

Comment: In response to the request for comments on whether EPA should "consider the affected sources (boilers) by themselves, or whether we should consider all HAP emissions at the facility when developing a 112(d)(4) standard" (FR 32,032), IECA believes that EPA should consider affected sources individually. Few significant sources of HCl exist beyond the industrial boilers and process heaters regulated under this proposed rule, other than utility boilers. Those utility boilers will be regulated by both the Utility MACT and the Clean Air Transport Rule, providing the EPA with ample opportunity to effect improvements to public health by regulating acid gas emissions from those units. EPA should not disproportionately burden industrial sources with the combined effects of their own emissions plus those of other sources by considering emissions from other affected sources in the area.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Ted Michaels
Commenter Affiliation: Energy Recovery Council
Document Control Number: EPA-HQ-OAR-2002-0058-2831.1
Comment Excerpt Number: 21

Comment: From a legal standpoint, the statute makes clear that criteria pollutant co-benefits associated with the proposed MACT standards may not be considered in deciding whether to establish Section 112(d)(4) health based emissions limitations. Also, EPA has failed to explain why the health based emissions limitations it established in the 2004 Boiler MACT rule and the justification provided for those limitations should now be reversed. The preamble to the newly proposed rule sets out a number of questions that might be relevant in deciding whether to establish health based emissions limitations, but merely asking questions is not a sufficient basis for reversing prior determinations adopted through notice and comment rulemaking. Thus, EPA's proposal not to set health based emissions limitations runs counter to the law and is based on an inadequate explanation of why the Agency proposes to depart from its prior approach.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Alicia Oman
Commenter Affiliation: National Association of Manufacturers
Document Control Number: EPA-HQ-OAR-2002-0058-2845.1
Comment Excerpt Number: 74

Comment: The co-benefits of collateral non-HAP emissions reductions cannot be used to justify a decision to ignore HBELs.

EPA explains in the proposal that "it considered the fact that setting conventional MACT standards for HCl as well as PM (as a surrogate for metals including manganese) would result in significant reductions in emissions of other pollutants, most notably SO2, non-consensable PM, and other non-HAP acid gases (e.g., hydrogen bromide) and would likely also result in additional reductions in emissions of mercury and other HAP metals (e.g., selenium)." 75 Fed. Reg. 32032. The Agency notes in particular that its belief that the rule will result in the reduction of up to 340,000 tons per year of SO2, which it characterizes as "substantial reductions with substantial health benefits." Id. EPA asserts that Congress acknowledged the possibility that MACT standards would result in collateral non-HAP emissions reductions and, therefore, that "the Agency may consider such benefits as a factor in determining whether to exercise its discretion under section 112(d)(4)." Id.

EPA is mistaken. Consideration of non-HAP collateral emissions reductions is impermissible in setting MACT standards. Section 112(d)(2) provides an express list of factors that EPA may consider in setting § 112(d) standards – including "the cost of achieving such emission reduction, and any non-air quality health and environmental impacts and energy requirements." This list does not allow consideration of non-HAP air quality benefits, such as the co-benefits of reducing PM2.5 emissions. This restriction is an unambiguous command that EPA should not consider non-HAP air quality benefits in setting standards under § 112(d). This prohibition extends of necessity not only to rules that literally list a criteria pollutant as a HAP but also to any rule that in effect treats a criteria pollutant as a HAP. National Lime Ass'n v. U.S. EPA, 233 F.3d 625, 638 (D.C. Cir. 2000).

By basing its rejection of the health-based approach for Boiler MACT on the co-benefits of criteria pollutant reduction, EPA is in effect unlawfully treating a criteria pollutant as a HAP. EPA's action here is not the simple use of a criteria pollutant as a surrogate for a HAP, which courts have upheld as long as EPA proves the scientific underpinning of the surrogate relationship. Id. Rather, EPA argues directly that it is the reduction in criteria pollutant emissions that causes it to reject the health-based approach. This EPA cannot do. [Footnote: Moreover, criteria pollutants from boilers are strictly regulated elsewhere under the Clean Air Act through New Source Performance Standards and other provisions of the Act.]

EPA's sole support for its "collateral benefits" theory is legislative history -- the Senate Report that accompanied Senate Bill 1630 in 1989. But the D.C. Circuit rejected precisely the same argument in National Lime. In that case, EPA supported its argument regarding particulate matter as a surrogate for HAP metals by referring to the same Senate Report discussed above. The court rejected EPA's argument, noting that the Senate Report referred to an earlier version of the statute that was ultimately not enacted, and hence was irrelevant:

The final statute, by contrast, unqualifiedly prohibits listing a criteria pollutant as a HAP, that is, regardless of the reason. Because the comment in the Senate Report regarding PM and metals was made before the blanket prohibition upon regulating PM as a HAP was added to the statute, the report is irrelevant to our construction of 7412(b)(2) as enacted.

National Lime at 638. Similarly here, EPA cannot use the language of a Senate Report that did not reflect the language of the statute as enacted to support its co-benefits theory and rejection of the health-based approach.

Moreover, even if it were relevant, the language in the Senate Report cited by EPA appears to address only area-source GACT standards under Section 112(d)(5), and therefore is not relevant to interpretation of MACT standards under Section 112(d)(2) or the health based alternative under Section 112(d)(4). And, in the final analysis, "it is the statute, and not the Committee Report, which is the authoritative expression of the law." City of Chicago v. Env. Defense Fund, 511 U.S. 328, 337 (1994). Here, the statute clearly provides that MACT standards may address only HAPs, not criteria pollutants. See National Lime Ass'n at 638.

But, even if it were not unambiguously prohibited, consideration of non-HAP air quality benefits under 112(d)(4) would be unreasonable. National Ambient Air Quality Standards ("NAAQS") are in place for all relevant pollutants, including ozone, SO2 , and PM. A MACT standard is a very imprecise tool for helping to attain and maintain such NAAQS because it imposes across-the-board requirements in circumstances where tailored solutions are needed. Each area has its own unique mix of sources and it own particular needs in terms of what reductions are needed and where such reductions should be achieved. SIP-based air quality programs provide the needed flexibility to design a program that effectively addresses local air quality needs. MACT standards are an unreasonably blunt instrument for dealing with non-HAP air quality issues.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 108

Comment: EPA Cannot Use section 112 As A Backdoor To Regulate Criteria Pollutants. EPA is proposing in this rule to set a MACT standard for HCl, and not a section 112(d)(4) health-based standard, in part because the MACT standard, in addition to the direct effect of reducing HCl, would also result in the reduction of non-HAP criteria pollutants emitted by boilers. EPA is using section 112 to further regulate and reduce emissions of criteria pollutants. This is impermissible for the reasons set forth below.

Under section 112(d)(4) EPA has the discretion to establish a health-based standard as an alternative to a technology driven standard for a HAP with a health threshold.[For "pollutants for which a health threshold has been established, the Administrator may consider such threshold level, with an ample margin of safety, when establishing emission standards under this subsection ." 42 U.S.C. section 7212(d)(4).] EPA chose not to do so here because, among other reasons, it determined that "MACT standards for HCl ... would result in significant reductions in emissions of other pollutants."[75 Fed. Reg. at 32139.] EPA's attempt to gain greater reductions in emissions of criteria pollutants through section 112 HAP limits is not allowed and this attempt is particularly unacceptable when EPA proposes to require the over-regulation of a threshold HAP to achieve those reductions.

The CAA clearly distinguishes regulation of HAPs from criteria pollutants. Section 112

"prohibits the addition of any criteria pollutant to "the list" of HAPs, with a single exception for certain precursor pollutants not relevant to this case. This prohibition extends of necessity not only to rules that literally list a criteria pollutant as a HAP but also to any rule that in effect treats a criteria pollutant as a HAP."[National Lime Ass"n v. U.S EPA, 233 F.3d 625, 638 (D.C. Cir. 2000).]
By basing its rejection of the health-based approach for HCl on the co-benefits of reducing emissions from a criteria pollutant, EPA is "in effect" unlawfully treating a criteria pollutant as a HAP. EPA's action here is not the simple use of a criteria pollutant as a surrogate for a HAP, which courts have upheld as long as EPA proves the scientific underpinning of the surrogate relationship.146 Rather, EPA argues directly that it is the reduction in criteria pollutant emissions that causes it to reject the health-based approach. This EPA cannot do.[Moreover, criteria pollutants from boilers are strictly regulated elsewhere under the CAA through NSPS and other provisions of the Act.]

EPA's sole support for its "collateral benefits" theory is legislative history -- the Senate Report that accompanied Senate Bill 1630 in 1989. But the D.C. Circuit rejected reliance on this Report in National Lime. In that case, EPA supported its use of PM, a criteria pollutant, as a surrogate for HAP metals by referring to the Senate Report discussed above. The court rejected EPA's argument, noting that the Senate Report referred to an earlier version of the statute that was ultimately not enacted, and hence was irrelevant:

The final statute, by contrast, unqualifiedly prohibits listing a criteria pollutant as a HAP, that is, regardless of the reason. Because the comment in the Senate Report regarding PM and metals was made before the blanket prohibition upon regulating PM as a HAP was added to the statute, the report is irrelevant to our construction of 7412(b)(2) as enacted.[National Lime at 638.]

Similarly here, EPA cannot use the language of a Senate Report that did not reflect the language of the statute as enacted to support its co-benefits theory and rejection of the health-based approach.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 109

Comment: Moreover, even if it were relevant, the language in the Senate Report cited by EPA appears to address only area-source GACT standards under Section 112(d)(5), and therefore is not relevant to interpretation of MACT standards under Section 112(d)(2) or the health based alternative under Section 112(d)(4). And, in the final analysis, "it is the statute, and not the Committee Report, which is the authoritative expression of the law." [City of Chicago v. Env. Defense Fund, 511 U.S. 328, 337 (1994).] Here, the statute clearly provides that MACT standards may address only HAPs, not criteria pollutants.[See National Lime Ass"n at 638.]

Response: See preamble for response to final decision on Health Based Compliance Alternative.

HBCA: Cost Impacts

Commenter Name: Richard Holland
Commenter Affiliation: Packaging Corporation of America
Document Control Number: EPA-HQ-OAR-2002-0058-2385
Comment Excerpt Number: 3

Comment: The 2004 version of the Industrial Boiler MACT included health based emissions limitations for HCl and manganese. Based on stack test results, a total of seven boilers located at three of our facilities were able to employ the 2004 rule’s HBCA allowance to demonstrate compliance for Particulate Matter and HCl. Under the new MACT proposal, those facilities are now required to install pollution control equipment at an estimated collective capital cost $42.3 million and additional annual operating costs of $4.1 million.

The health-based emissions limitations established in the 2004 MACT rule were developed under rigorous standards that protected public health with an ample margin of safety. EPA can and should set health-based standards that are clearly and unequivocally allowed by the Clean Air Act.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Tim Keneally

Commenter Affiliation: KapStone Paper and Packaging Corporation
Document Control Number: EPA-HQ-OAR-2002-0058-2673.1
Comment Excerpt Number: 3

Comment: It was estimated at the time that these health-based standards would have saved over $2 billion in compliance costs, as compared to the technology-based standards that otherwise would have applied.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Theresa Pugh
Commenter Affiliation: American Public Power Association
Document Control Number: EPA-HQ-OAR-2002-0058-2714.1
Comment Excerpt Number: 4

Comment: EPA's decision to eliminate health-based emissions limits is particularly troubling given its conclusion that the proposed rule is likely to affect a substantial number of small entities, including small governments operating public power systems. Upon reaching this conclusion, EPA had an affirmative duty under the Small Business Regulatory Enforcement Fairness Act (SBREFA) to consider compliance costs and regulatory alternatives that could ease the burden on small entities. As part of this effort, EPA convened the Small Business Advocacy Panel, which identified health-based compliance alternatives as "the most important step EPA could take to mitigate the serious financial harm the Boiler MACT would otherwise inflict on small entities using solid fuels nationwide . . . ." When EPA adopted a health-based alternative for HCl in 2004, it estimated that affected sources would save $2 billion in compliance costs at no expense to human health or the environment. This could be a low estimate, because one small government municipal utility has received a cost estimate for over $22 million to control HCl emissions; the same HCl emissions that posed no health threat under the 2004 Boiler MACT rule. In fact, EPA approved the health-based compliance alternative for this facility in 2007 recognizing that its stack height and distance to fence line assured protection of human health with an ample margin of safety. Yet EPA provided no explanation for why an HBEL is no longer available to this small government and the many like it and what now justifies wasting billions of dollars in compliance costs on pollutants for which EPA cannot demonstrate an adverse health effect. EPA's decision to eliminate HBELs from the proposed rule without justifying its departure from EPA's 2004 reasoning is arbitrary and capricious.

If unable to comply, APPA members may be forced to abandon the standby and backup capacity, and start-up boilers, at significant detriment to the reliability of the electricity service provided. As such, work practices under 112(h) are needed, or preferably limited use exemptions for boilers operating less than 10% of their annual heat input capacity, to ensure reliable and efficient electricity service.

Response: See preamble for response to final decision on Health Based Compliance Alternative. See preamble for discussion of the limited-use subcagetory.

Commenter Name: Douglas A. McWilliams
Commenter Affiliation: American Municipal Power
Document Control Number: EPA-HQ-OAR-2002-0058-2808.1
Comment Excerpt Number: 2

Comment: As EPA recognized, the proposed Boiler MACT rule will likely have a significant impact on a substantial number of small entities. 75 Fed. Reg. at 32044. Given that EPA has set emissions standards that no existing units can meet, it is likely that every existing unit subject to an emission standard will need to be retrofitted. Even AMP member the City of Painesville, which is listed as one of the top performing sources for HC1 emissions in EPA's database, would need control equipment to ensure that it can meet the proposed HC1 standard of 0.02 lb/mmBtu at all times. We are attaching the original stack test reports and additional stack test reports for Painesville's stoker units (Unit 3 and Unit 4) that should be included in EPA's database (see submittal for stack test reports) and used to recalculate the MACT floor emission rates. These snapshot test runs indicate significant variability in HC1 emissions (0.002 to 0.021 lb/mmBtu) resulting in an upper predicted emission rate in excess of the proposed emission limit for stoker coal boilers. Painesville was the only AMP member in the top performing 12% of the existing sources in EPA's database. Without further relief, all members would thus face control technology costs to address HC1 emissions from sources that have been demonstrated to be below the 2004 Health Based Compliance Alternative for HC1 concentrations at the fence line. For small municipal utilities, the cost of these retrofits is staggering. The City of Orrville and the City of Painesville operate municipal electric plants that provide electricity to the residents and businesses of their respective communities in Ohio. Each independently evaluated the cost of controlling HC1 emissions and determined that the capital cost for an acid gas scrubber to meet the proposed emission limits for a single unit would be $5-16 million. Additional annual operating costs were estimated to be $900,000 to $1.2 million per year. Orrville operates four units and Painesville operates three. Thus, the facility-wide capital cost for HC1 control alone could exceed $40 million with another $3-4 million per year in annual operating costs. This represents $33,000 per customer in capital costs and an additional $3,000 per customer for annual operating costs. These costs pose insurmountable burdens on small municipal electric systems to reduce HC1 emissions that do not pose a health risk.
For many small entities, the capital costs alone will force them to shut down. For AMP member St. Marys, the threat of millions of dollars in additional annual operating costs made continuing operations uneconomical and impractical and they shut down operations in anticipation of the Boiler MACT rule. Others will follow if EPA fails to achieve a better balance between benefit and burden in this rule. [Footnote: Even capital costs of less than $1 million are an impossibility for some small businesses. As Thomas Machamer of Cedar Lane Farms Corporation notes, the $500,000 in control equipment and installation costs necessary to comply with proposed rules represents "nearly half of our yearly sales" and "will put us out of business." See Letter from Thomas Machamer, President, Cedar Lane Farms Corp., to Jim Eddinger, U.S. EPA, re: Rulemakings, HAPs and Public Comments (Dec. 2, 2008)] Implementation of this rule will significantly hinder municipal utilities' ability to provide reliable electrical services to their

communities, peaking capacity to avoid brownouts, and quality work opportunities for local residents. Adopting MACT standards that force small entities to severely curtail or eliminate operations is contrary to the intent of Congress, v?hich has stated that -.MACT is not intended to . . . drive sources to the brink of shutdown." I lousE REP. No. 101-490, Part 1 (1990) at 328. But that is precisely what will happen to small entities under the Proposed Rule unless changes are made.

Adoption of an HBEL for HC1 would significantly reduce the cost burden mandated by the Proposed Rule that would otherwise crush numerous small entities. The Small Business Advocacy Panel, convened by EPA, identified health-based compliance alternatives as "the most important step EPA could take to mitigate the serious financial harm the Boiler MACT would otherwise inflict on small entities using solid fuels nationwide. . . ." SBA REVIEW PANEL, FINAL REPORT at 23 (emphasis added). HBELs would provide regulatory flexibility by allowing small entities to meet emission limitations that are protective of human health and the environment without investing millions of dollars in unnecessary control equipment. Small municipalities, which already struggle to provide services in the face of shrinking revenues, should not be forced to spend millions of dollars badly needed elsewhere on control equipment that will provide no additional health or environmental benefits.

These health-based emissions limitations were rigorous standards that demanded accountability. They were a winner for the Agency and the public because public health would have been protected with an ample margin of safety. At the same time these standards were a winner for affected sources because the standards would not have required expensive control equipment to blindly reduce emissions below levels necessary to assure public safety. It was estimated at the time that these health-based standards would have saved over $2 billion in compliance costs, as compared to the technology-based standards that otherwise would have applied. For small public utilities like Painesville and Orrville, health-based standards could cut compliance costs in half and allow these and other small entities to avoid shutdown or reductions in essential services with no danger to the public health or the environment.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Douglas A. McWilliams
Commenter Affiliation: American Municipal Power
Document Control Number: EPA-HQ-OAR-2002-0058-2808.1
Comment Excerpt Number: 6

Comment: While EPA has discretion in deciding whether to set HBELs under section 112(d)(4), the Agency cannot be arbitrary and capricious in making such a decision. The proposed HC1 and PM emissions limitations for all types of industrial boilers are exceedingly stringent. Affected sources will have to spend tens of millions of dollars in order to meet the standards, and a significant number of existing units simply will not be able to meet the standards and will be forced to shut down. Shutclovm for small entities in particular is likely given the tremendous costs associated with the control equipment necessary to meet proposed emission limits.

The costs and burdens on affected sources and the degree of control needed to provide adequate health and environmental protection are both key factors that should be considered by the

Agency in deciding whether to adopt HBELs in the Boiler MACT rule. EPA has an affirmative duty to consider the costs imposed on small businesses and government entities pursuant to the Unfunded Mandates Reform Act and the Regulatory Flexibility Act, as amended by the Small Business Regulatory Enforcement Fairness Act, and to consider the costs of alternative regulatory approaches. However, the Agency's discussion of HBELs includes no assessment whatsoever of the costs that might be avoided by adopting HBELs for HC1 or manganese. This failure is significant, as the scrubber technologies needed to meet proposed HC1 limits make up more than half the estimated capital and operating costs small entities like Orrville are expected to incur for Boiler MACT compliance. These costs could well mean the difference between shutting down and continuing as a viable business to small entities. As to potential effects on health or the environment, EPA simply raises implementation questions and asserts a lack of information. Such an approach is facially inadequate in light of the extensive policy, scientific, and technical assessment developed in support of the HBELs in the 2004 Boiler MACT rule standard.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Christy Sammon
Commenter Affiliation: Southeast Lumber Manufacturers Association
Document Control Number: EPA-HQ-OAR-2002-0058-2727.1
Comment Excerpt Number: 17

Comment: Without a health-based compliance option, many of our members will be faced with the prospect of having to close their facilities because of the inability to spend the required millions of dollars to attempt to meet the proposed limits, or to purchase natural gas boilers, which would cost less than the required controls, and face huge increases in operating costs as a result. These increased costs would make the U.S. wood products industry uncompetitive with mills in Canada and elsewhere around the world. The wood products industry is one of the largest industrial employers in the southeastern states, and these high paying jobs are put at risk if unjustified and unreasonable limits are imposed.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Duane Mummert
Commenter Affiliation: South Carolina Chamber of Commerce Environmental Technical Committee
Document Control Number: EPA-HQ-OAR-2002-0058-3171
Comment Excerpt Number: 2

Comment: When the first Industrial Boiler MACT was promulgated in 2004, it included health based emissions limitations for two HAPs — hydrogen chloride ("HCI") and manganese. These health-based emissions limitations were rigorous standards that demanded accountability. They were a winner for the Agency and the public because public health would have been protected with an ample margin of safety. At the same time these standards were a winner for affected sources because the standards would not have blindly required emissions to be reduced far below the levels needed to assure that the public was protected. It was estimated at the time that these health based standards would have saved over $2 billion in compliance costs, as compared to the technology-based standards that otherwise would have applied. The ETC requests EPA reconsider their decision not to include these health-based limitations in the newly proposed Industrial Boiler MACT.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Edward E. Quick
Commenter Affiliation: Celanese International Corp
Document Control Number: EPA-HQ-OAR-2002-0058-2840.1
Comment Excerpt Number: 3

Comment: EPA should not abandon the health-based HCl standard. EPA should exercise its discretion to establish health based emission limits (HBEL). Celanese recognizes the effort required to pursue this compliance alternative but believes the benefits far outweigh the burdens based on the following:

-The costly and burdensome effect of installing scrubber technology in this time of economic distress may severely damage industry's ability to operate economically.

-The potentially devastating economic effects on the US economy and energy markets as a whole, given that many regulated sources will choose to comply with the proposed standards by switching to natural gas.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Jim Weeks
Commenter Affiliation: Michigan Municipal Electric Association
Document Control Number: EPA-HQ-OAR-2002-0058-2795.1
Comment Excerpt Number: 4

Comment: Marquette and Holland are concerned that the controls that would he required by the proposed MAUI' standard for HCl control from electric units will be unachievable and uneconomic, and could lead to the shuttering of these critical units. It should he noted that these units demonstrated compliance with the 2004 health based compliance alternative, which was set at a level that fully protected human health with an ample margin of safety.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Jerry Osheka
Commenter Affiliation: PPG Industries
Document Control Number: EPA-HQ-OAR-2002-0058-2938.1
Comment Excerpt Number: 9

Comment: When the first Industrial Boiler MACT was promulgated in 2004, it included health-based emissions limitations for two HAPs – hydrogen chloride (“HCl”) and manganese. These health-based emissions limitations were rigorous standards that demanded accountability. This presented a win for the Agency and the public because public health would have been protected with an ample margin of safety. At the same time these standards were reasonable for affected sources because the standards would did not blindly require emissions to be reduced far below the levels needed to assure that the public was protected and as a result did not require unnecessary expense for the installation of unnecessary controls. It was estimated at the time that these health based standards would save over $2 billion in compliance costs, as compared to the technology-based standards that otherwise would have applied. Under the current proposed rule and proposed HCl emissions limits, PPG estimates it will cost at least $100 million to install and upgrade required emissions controls on our boilers at our single coal-fired facility. We estimate, if health-based emissions limits are provided, that cost of compliance will drop to approximately $20 million – not an insignificant amount, but certainly a significant cost-reduction. During this fragile economic recovery, imposing unnecessary cost burdens of this magnitude onto industrial firms that are daily exposed to foreign competition, in order to achieve an unspecified health benefit that is merely assumed and not supported by peer-reviewed research, is wholly unreasonable and capricious. PPG urges EPA to establish health-based emissions limits to protect both the public health and the high-quality jobs that American industry provides.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Bill Perdue
Commenter Affiliation: American Home Furnishings Alliance
Document Control Number: EPA-HQ-OAR-2002-0058-2692.1
Comment Excerpt Number: 9

Comment: At a time when our industry is struggling to survive, it is incumbent upon EPA to consider a 112(d)(4) HBCA for these substances. We recommend that such an HBCA comprise a tiered approach beginning with a lookup table matching emission rates and physical parameters to threshold exemptions, followed by a site-specific dispersion modeling and offsite risk demonstration option for those sources that cannot demonstrate compliance using the lookup tables.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Mark W. Kowlzan
Commenter Affiliation: Packaging Corp. of America
Document Control Number: EPA-HQ-OAR-2002-0058-2913.1
Comment Excerpt Number: 10

Comment: The 2004 version of the Industrial Boiler MACT included health based emissions limitations for HCI and manganese. Based on stack test results, a total of seven boilers located at three of our facilities were able to employ the 2004 rule's HBCA allowance to demonstrate compliance for Particulate Matter and HC\. Under the new MACT proposal, those facilities are now required to install pollution control equipment at an estimated collective capital cost in excess of $42 million and additional annual operating costs of $4.1 million, with no measurable improvement in public protection.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Tracy Smith
Commenter Affiliation: Coastal Forest Products
Document Control Number: EPA-HQ-OAR-2002-0058-2872.1
Comment Excerpt Number: 12

Comment: Without a health-based compliance option, many wood products mills will be faced with the prospect of having to close their facilities because of the inability to spend the required millions of dollars to attempt to meet the proposed limits, or to purchase natural gas boilers, which would cost less than the required controls, and face huge increases in operating costs as a result. These increased costs would make the U.S. wood products industry uncompetitive with mills in Canada and elsewhere around the world which are not subject to the stiffly standards proposed by EPA. The wood products industry is one of the largest industrial employers in the southeastern states, and these high paying jobs are put at risk if unjustified and unreasonable limits are imposed.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Traylor Champion
Commenter Affiliation: Georgia-Pacific LLC
Document Control Number: EPA-HQ-OAR-2002-0058-2745.1
Comment Excerpt Number: 13

Comment: This will significantly reduce compliance costs.
As noted above, these rules could cost $6 billion over the next four years for the forest products industry. This would result in tens of millions in additional, non-sustainable capital expenditures

and significant job losses. GP could spend hundreds of million of dollars at its 82 solid fuel and oil-fired boilers. Were EPA to adopt the additional flexibility of a health based compliance option, combined with a TSM compliance option, GP could save tens of millions of dollars while still protecting the environment as envisioned by the Clean Air Act.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Paul N. Cicio
Commenter Affiliation: Industrial Energy Consumers of America
Document Control Number: EPA-HQ-OAR-2002-0058-2752.1
Comment Excerpt Number: 13

Comment: EPA states that respiratory toxicity effects from HCl exposure are known and understood, and cites a reference concentration (RfC) for HCl that is presumed adequate to protect human health. EPA further states that there is limited data examining the carcinogenicity of HCl. Then EPA contends that while the agency is "aware of no studies explicitly addressing the toxicity of mixtures of HCl with other respiratory irritants," it makes the extraordinary leap of assuming "an additive cumulative effect" of HCl with other HAPs (FR 32,031). IECA contends that such a conclusion, drawn despite the lack of any supporting data, is wholly inappropriate. IECA urges EPA to establish a HBCA process for sources to demonstrate adequate protection of human health as allowed under §112(d)(4) of the Clean Air Act, by considering emissions of HCl, Cl2, HF and HCN from the affected source in comparison against the appropriate RfC. IECA contends that evaluating a source's HCl emissions against the RfC will provide ample protection to public health with a margin of safety.
Unless quantitative, peer-reviewed data showing the additive cumulative effect of acid gases with other HAPs is produced, EPA's assumption that this purported effect does exist imposes an unreasonable cost burden on many small sources with wholly unsupported health benefits in return. One member company determined the cost to install acid gas scrubbers on its industrial boilers at a single site would exceed $200 million. During this fragile economic recovery, imposing cost burdens of this magnitude onto industrial firms that are daily exposed to foreign competition, in order to achieve an unspecified health benefit that is merely assumed and not supported by peer-reviewed research, is wholly unreasonable and capricious. IECA urges EPA to allow HBCA provisions to protect both the public health and the high-quality jobs that American industry provides.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 150

Comment: ACC supports the inclusion of risk-based limits for HCl and other threshold pollutants as a means of minimizing investments that would do little in terms of reducing risk from boiler emissions.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Other - Health Based Compliance

Commenter Name: Ritchie Monteith
Commenter Affiliation: AbitibiBowater - Catawba Operations
Document Control Number: EPA-HQ-OAR-2002-0058-0849.1
Comment Excerpt Number: 4

Comment: It is critical that the EPA create more flexibility in the rule. We need this flexibility in order to choose more efficient alternatives.

Response: See preamble for response to final decision on Health Based Compliance Alternative. See preamble for rationale for selecting a work practice for these Gas 1 units. See preamble for discussion of the limited-use subcategory.

Commenter Name: N/A
Commenter Affiliation: Citizen
Document Control Number: EPA-HQ-OAR-2002-0058-1840
Comment Excerpt Number: 2

Comment: I oppose any effort to establish a lesser "health-based" standard for acid gases.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Mark Petty
Commenter Affiliation: Flambeau River Papers
Document Control Number: EPA-HQ-OAR-2002-0058-1753.1
Comment Excerpt Number: 3

Comment: The EPA should use an approach to set all the standards that are based on what real world boilers actually can achieve. High quality data should be used in making decisions after careful review by EPA. And, facilities should not be forced to install controls where analyses show emissions are safe.

EPA's proposed Boiler MACT can be crafted in a more balanced way that sustains both the environment and good jobs and doesn't hurt our ability to compete against imported products. If EPA were to provide more flexible approaches in the final Boiler MACT rule and appropriately address the diversity of boilers and fuels in use, it could achieve its goal while preventing severe job losses and billions of dollars in unnecessary regulatory costs.

Response: See preamble for response to final decision on Health Based Compliance Alternative. See preamble for rationale for selecting a work practice for these Gas 1 units. See preamble for discussion of the limited-use subcategory and incorporation of statistical variability within MACT floor methodology.

Commenter Name: Houston Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1876
Comment Excerpt Number: 5

Comment: Allow use of health-based compliance alternatives where appropriate in lieu of the hydrogen chloride and manganese limits as EPA did in the original Boiler MACT

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Charles McRae
Commenter Affiliation: Rex Lumber
Document Control Number: EPA-HQ-OAR-2002-0058-1846
Comment Excerpt Number: 5

Comment: EPA should retain a health-based compliance option so that facilities are not required to install unnecessary controls.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Houston Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1876
Comment Excerpt Number: 11

Comment: What Scotch Plywood would like to be considered is the public health option that was considered in the plywood MACT, also available for the Boiler MACT.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Los Angeles Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1778
Comment Excerpt Number: 17

Comment: EPA should use its authority in section 112(d)(4) of the Clean Air Act to set health-based emission limits to protect the environment and public health. In order for companies to deploy capital to the right mills, tests for compliance should be done on a facility-by-facility basis. With the many different types of boilers utilized by the industry, one size does not fit all.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Los Angeles Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1778
Comment Excerpt Number: 29

Comment: EPA also has the authority in section 112(d)(4) of the Clean Air Act to set health-based emission limits to protect the environment and human health. This would avoid unnecessary controls where emissions of threshold pollutants are low enough to be safe. We're encouraged that EPA invited comment on this, and we believe it should be adopted in the final rule on a facility-by-facility basis. The best way to target investments is where actual problems exist.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Houston Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1876
Comment Excerpt Number: 33

Comment: The final rule should include an option for health-based standards. The proposed rule would force many harmless rural facilities that pose absolutely no risk to human health or the environment to either install unnecessary and costly controls or shut down. Coastal encourages EPA to establish health-based emission limits to be applied on a facility-by-facility basis in order to avoid control where it can be demonstrated that emissions are safe.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Houston Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1876
Comment Excerpt Number: 40

Comment: I would like to reiterate that AF & PA will be helping to provide the data that you -- you seek with regard to the health -- health-based emission issue, and we pledge to work with you on that and see if we can help you focus on that issue with some good data, and we will be helping to provide that.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Houston Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1876
Comment Excerpt Number: 44

Comment: Georgia-Pacific supports efforts to address serious health threats from air emissions, and supports regulations that sustain both the environment and the nearly 900,000 men and women that our industry employs. Unfortunately, the rule proposed by EPA in June does not accomplish these objectives. Georgia-Pacific is prepared to work with the EPA to protect both public health and jobs by targeting environmental investments where there is a real need. If the EPA were to provide more flexible approaches in the Boiler MACT rule and appropriately address the diversity boilers, operations, sectors, and fuels, it could achieve its goal while preventing severe job losses and billions of dollars in unnecessary regulatory costs.

Response: See preamble for response to final decision on Health Based Compliance Alternative. See preamble for rationale for selecting a work practice for these Gas 1 units. See preamble for discussion of the limited-use subcategory and incorporation of statistical variability within MACT floor methodology.

Commenter Name: Houston Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1876
Comment Excerpt Number: 46

Comment: MR. BOYCE: Yes, as far as -- you said provide more flexible approaches. I was just wanting an example of one or two that you might think of or might add as flexible rule.

MR. BURCH: Well, just like the cluster rule. The cluster rule was, what, ten years ago? Just something simple like that. It wasn't simple for us, but still it cleaned the air up. I don't see where -- in my mill alone, we can tell the air around us has improved just from the smell.

Response: See preamble for response to final decision on Health Based Compliance Alternative. See preamble for rationale for selecting a work practice for these Gas 1 units. See preamble for discussion of the limited-use subcategory and incorporation of statistical variability within MACT floor methodology.

Commenter Name: Los Angeles Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1778
Comment Excerpt Number: 46

Comment: Now, it's probably never a good idea to complain about something without offering a solution.
We suggest the use of a health risk analysis in lieu of the one-size-fits-all regulations that are proposed.
Some years ago California enacted what is called the Air Toxics Hot Spots Program, the AB2588 program, which requires a health risk analysis based on power plant emissions and toxics. This was done in California and a number of years ago. All biomass plants were suggested to the health risk analysis and all passed. We burn clean wood chips. Unfortunately, the category of fuel known as Construction and
Demolition Wastes referred to as C and D, they're looped together.
Our plants take construction waste with clean cutoffs. Our permits prohibit painted or otherwise treated wood in our fuel plant. So demolition waste is generally completely ruled out. We would suggest that in lieu of either the Boiler MACT or the
Area Source Rule for biomass power plants not burning waste but burning clean wood chip fuel, be subjected to a health risk analysis based on measured stack emissions and accepted health risk methodologies.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Los Angeles Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1778
Comment Excerpt Number: 52

Comment: EPA should utilize its authority in Section 112(d)(4) of the Clean Air Act to set health-based emission limits to protect the environment and the public health. Health-based limits would avoid unnecessary over-regulation of emissions that are already within acceptable limits. We can ill-afford not to include such a health-based emission limitation given the economic implications of the rule.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Houston Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1876
Comment Excerpt Number: 52

Comment: Include a Health Based Compliance Alternative. EPA included options in the original standard to allow sources to demonstrate an alternative standard that was protective of health and the environment. EPA has chosen not to do so in the proposed rules. Further, it has set up a nearly impossible standard to meet in the Preamble to the
Boiler MACT Rule, if it were to consider such an alternative. MeadWestvaco believes that EPA has an obligation to ensure that standards it requires are imposed due to a reasonable risk to the health and the environment and not due to a mathematical exercise.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Houston Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1876
Comment Excerpt Number: 57

Comment: Facilities that originally met the very conservative health-based compliance option must now install a series of control device costing millions of dollars. Without a health-based compliance alternative, most wood products facilities would either close down or purchase natural gas boilers, which can be obtained at a fraction of the cost of the required control.
The biomass fuel would then be sent to a landfill where it would degrade to methane.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Los Angeles Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1778
Comment Excerpt Number: 68

Comment: EPA should include a health threshold standard in the final rule to target environmental investments where there is a real need based on a rigorous demonstration of pollutants like hydrogen chloride and manganese do not pose an adverse risk.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Houston Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1876
Comment Excerpt Number: 73

Comment: Set health-based emission rules that reflect the true impact on people. Four, change the methodology used to determine what the ideal MACT boiler would operate like. The EPA's approach severely biased the data and is not representative of the current universe of operating boilers and in conflict with the law.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Houston Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1876
Comment Excerpt Number: 80

Comment: We encourage that the EPA has invited comment and gives Section 112, which allows facilities to avoid controls where risks of structural pollutants like gases and manganese are shown to be safe. We believe this approach should be adopted and a final rule for use on a facility-by-facility basis.
That's a surefire way to target investment to only where problems exist, and it's absolutely imperative that we take a health-based approach, given the economic implications of this rule.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Houston Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1876
Comment Excerpt Number: 97

Comment: EPA should utilize its authority in section 112(d)(4) of the Clean Air Act to set health-based emission limits. Health-based limits would avoid unnecessary overregulation of emissions that are already well within acceptable levels. We can ill-afford not to include such a based health-based emissions limitation given the economic implications of this rule.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Houston Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1876
Comment Excerpt Number: 126

Comment: Norbord proposes greater effort be made to involve industry experts in establishing technically sound and cost-effective options and emission limits. Facilities should have the option to avoid installing controls where risk analysis determines emissions are within safe limits. EPA's goals can be achieved without excessive regulatory compliance costs which could cripple industries to compete internationally. We can do the reasonable thing now rather than resort to court challenges later.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Houston Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1876
Comment Excerpt Number: 135

Comment: EPA needs to include the use of Clean Air Act Section 112(d)(4) to establish health-based emission limitations on a facility-by-facility basis using a reasonable demonstration method without unnecessarily complicated procedures. This will target environmental investments where there is a real need.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Houston Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1876
Comment Excerpt Number: 147

Comment: EPA should utilize Clean Air Act Section 112(d)(4) to establish health-based emission limitations to protect the environment and public health. This will avoid the use of unnecessary controls when emissions of pollutants are low enough to be safe. The use of health-based emission limitations will be no more stringent or less stringent than needed and will also target environmental investments where there is a real need.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Fred T. Simpson
Commenter Affiliation: Scotch Gulf Lumber, LLC
Document Control Number: EPA-HQ-OAR-2002-0058-1899.1
Comment Excerpt Number: 2

Comment: EPA should retain a health-based compliance option in Boiler MACT so that facilities such as Scotch Gulf Lumber that burn only clean biomass are not required to install unnecessary controls for particulate matter as a surrogate for metal hazardous air pollutants.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Arlington Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1779
Comment Excerpt Number: 3

Comment: First, EPA should utilize its authority in Section 112(d)(4) of the Clean Air Act to set health-based emission limits to protect the environment and public health. This would avoid unnecessary controls where emissions of threshold pollutants, like acid gases, are low enough to be safe.
We are encouraged that EPA has invited comment on this approach and believe it should be adopted in the final rule for use on a facility-by-facility basis without complicated and unnecessary procedures that would restrict its use. It is the best way to target investments only to where problems exist as Congress intended. We can ill afford not to include such a health-based emission limitations given the economic implications of the rule.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Thomas C. Ludlow
Commenter Affiliation: JWTR, LLC
Document Control Number: EPA-HQ-OAR-2002-0058-1870
Comment Excerpt Number: 4

Comment: We urge the agency to consider, as they mention in the proposal, that the rule should allow facilities to avoid installing controls where there is a reasonable case that emissions are safe.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Allan Muller
Commenter Affiliation: Green Delaware
Document Control Number: EPA-HQ-OAR-2002-0058-1911
Comment Excerpt Number: 4

Comment: Stringent health-based and technology-based (MACT) requirments are urgently needed.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: David Meeker
Commenter Affiliation: National Renderers Association
Document Control Number: EPA-HQ-OAR-2002-0058-1868.1
Comment Excerpt Number: 5

Comment: EPA should allow facilities to demonstrate that emissions of certain pollutants do not pose a public health concern. A practical health oriented standard for threshold pollutants would allow sources to demonstrate their emissions of these compounds pose no adverse risk. The Clean Air Act in §112(d)(4), expressly contemplates the use of such an approach which can be implemented without sacrificing risk reduction benefits. A health threshold standard is critical to the future viability of biomass and other boiler fuels. EPA has indicated to stakeholders that this alternative will not be part of the proposed rule language. EPA should revisit this thinking and make the health threshold standard an integral part of its proposed Rules and allow an opportunity for public comment on this approach.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Carl Johnson
Commenter Affiliation: Southern Pressure Treaters' Association
Document Control Number: EPA-HQ-OAR-2002-0058-1867.1
Comment Excerpt Number: 9

Comment: The health-based compliance option should be retained to prevent facilities from having to install unnecessary controls.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Arlington Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1779
Comment Excerpt Number: 19

Comment: EPA has chosen not to establish a health-based emission standard for threshold pollutants in lieu of a MACT standard. Based on our preliminary review and bolstered by the work performed by EPA in support of the health threshold option included in the 2004 rule, ACC strongly recommends that the Agency consider the fact that the proposed standards for HCl are far more stringent than needed to assure protection of public health with an ample margin of safety.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Arlington Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1779
Comment Excerpt Number: 43

Comment: Several options have been proposed for which EPA offered little or no justification and analysis. Some are of doubtful legality o—in particular, the clearly erroneous suggestion that EPA could establish risk-based exemptions at levels less stringent than the MACT floor. NACAA recommends that EPA avoid options that carry a substantial risk of a lawsuit that delays implementation of these important public health protections.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Arlington Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1779
Comment Excerpt Number: 85

Comment: It is critical that the EPA create more flexibility in the rule. We need this flexibility in order to choose more efficient alternatives.

Response: See preamble for response to final decision on Health Based Compliance Alternative. See preamble for rationale for selecting a work practice for these Gas 1 units. See preamble for discussion of the limited-use subcategory and incorporation of statistical variability within MACT floor methodology.

Commenter Name: Arlington Public Hearing Transcript
Commenter Affiliation: See transcript for detailed list of commenters
Document Control Number: EPA-HQ-OAR-2002-0058-1779
Comment Excerpt Number: 92

Comment: Requiring this investment means additional job losses in our industry and in the important manufacturing sector of our economy. At a time when we should be promoting job and economic growth at home, we are handicapping U.S. industry with a new layer of regulations that are unproven to provide any health or environmental benefit.

Two particular components of the Boiler MACT regulation are of particular concern. The first is the lack of any health-based assessment. When the Clean Air Act was first developed, Congress established that lowering emissions further would only be necessary when there are clearly-defined health benefits. Without a health-based assessment, the regulation could require significant investments in actions that would not provide any corresponding benefit.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Jim Hickman
Commenter Affiliation: Langdale Forest Products Co.
Document Control Number: EPA-HQ-OAR-2002-0058-2065.1
Comment Excerpt Number: 6

Comment: EPA should retain a health-based compliance option so that facilities are not required to install unnecessary controls.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Randy Thurman and Brent Stevenson
Commenter Affiliation: Arkansas Environmental Federation and Arkansas Forest & Paper Council
Document Control Number: EPA-HQ-OAR-2002-0058-2719.1
Comment Excerpt Number: 2

Comment: We encourage EPA to consider flexible approaches that appropriately addresses the diversity of boilers, operations, sectors and fuels that could prevent severe job losses and billions of dollars in unnecessary regulatory costs. We believe that it is Congress' intent to provide for flexibility where there is not a public health threat and that flexibility is provided in the Clean Air Act, Section 112 (d)(4). EPA should avail itself of the flexibility allowed, rather than reject it and result in further job losses.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Charles R. Faulds
Commenter Affiliation: Texas Electric Cooperatives, Treating Division
Document Control Number: EPA-HQ-OAR-2002-0058-2526.1
Comment Excerpt Number: 5

Comment: EPA should retain a health-based compliance option so that facilities are not required to install unnecessary controls.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Kevin Bilbrey
Commenter Affiliation: Clarke County Pole and Piling Co, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-2414.1
Comment Excerpt Number: 5

Comment: EPA should retain a health based compliance option so that facilities are not required to install unnecessary controls.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: N/A
Commenter Affiliation: Sierra Club, Clean Air Task Force, Earthjustice, and Natural Resources Defense Council
Document Control Number: EPA-HQ-OAR-2002-0058-3187.1
Comment Excerpt Number: 61

Comment: The Administrator must evaluate the potential for environmental impacts when considering whether to exercise her discretion under § 112(d)(4). As the legislative history indicates, and EPA correctly notes, "employing a §112(d)(4) standard rather than a conventional MACT standard 'shall not result in adverse environmental effect which would otherwise be reduced or eliminated.' " 75 Fed. Reg. 32,031 (emphasis added) (quoting S. Rep. No. 228, 101st

Cong., 1st Sess. (1989) at 171). It is therefore not only “appropriate to consider potential adverse environmental effects in addition to adverse health effects when setting an emission standard . . . under 112(d)(4),” Id. 32,031(emphasis added), EPA must do so, and must show that any resulting health threshold based standard does not cause adverse environmental effects in excess of those that would result from a MACT standard.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 137

Comment: CAA 112(d) enables EPA to establish alternative MACT standards by applying provisions such as the HBEL to avoid unnecessary regulation for HAPs that do not pose a health risk. In 2004, EPA determined that two HAPs commonly emitted from solid fuel industrial boilers, hydrogen chloride (HCl) and manganese (Mn), are threshold pollutants that do not pose a significant health risk at a potentially large proportion of regulated sources. If it can be demonstrated that health benchmarks are met for these HAPs, emission controls for these materials are not deemed to be necessary.

Similar considerations for addressing HCl as a threshold pollutant have been included in 1) National Emission Standards for Hazardous Air Pollutants: Final Standards for Hazardous Air Pollutants for Hazardous Waste Combustors (Phase I Final Replacement Standards and Phase II); Final Rule; 2) National Emission Standards For Hazardous Air Pollutants; Proposed Standards For Hazardous Air Pollutants From Chemical Recovery Combustion Sources At Kraft, Soda, Sulfite, And Stand-Alone Semichemical Pulp Mills; 3) National Emission Standards for Hazardous Air Pollutants From the Portland Cement Manufacturing Industry; and 4) National Emission Standards for Hazardous Air Pollutants: Chlorine and Hydrochloric Acid Emissions From Chlorine Production. In the absence of specific scientific evidence to the contrary, it has historically been EPA’s policy to classify non-carcinogenic effects as threshold effects, as demonstrated in the above rulemakings.
The logic provided by EPA in developing the 2004 HBCA was a direct interpretation of 112(d)(4). In summary:
* Hydrogen chloride is the chief acid gas HAP from solid fuel combustion and emissions are related to chloride and chlorine content in fuel. Hydrogen chloride and chlorine are threshold HAPs with associated similar effects and established Reference Concentrations (RfC), such that the combined inhalation risk of these HAPs can be considered collectively.

* Manganese is a threshold HAP metal, which is a chief risk driver for wood-fired boilers. The 2004 Boiler MACT included emission standards for Total Selected Metals (TSM), of which manganese was a component. The HBCA would exempt manganese from the TSM calculation.

* 112(d)(4) was interpreted to require that all MACT boilers (i.e., from the same MACT source category) at a single facility not significantly contribute to risk. It does not require risk evaluation of other HAPs with different types of health effects or contribution from other sources or background concentrations, as presently suggested in the proposed rule. In 2004, EPA stated the basis for this determination in response to comments that cumulative risks should be evaluated under the HBCA. EPA responded that 112(d)(4) does not indicate that a risk assessment should be undertaken, but simply that the threshold level of a particular HAP should be considered and that it is appropriate to consider cumulative risk under 112(f), which requires the evaluation of residual risk after the implementation of MACT standards. Section 112(f)(1)(c) states that EPA will address "actual health effects with respect to persons living in the vicinity of sources, any available epidemiological or other health studies, risks presented by background concentrations of hazardous air pollutants" in the residual risk assessments.

Rather than this direct interpretation of the CAA 112(d)(4) applied by EPA in 2004, the preamble to the 2010 proposed Boiler MACT repeatedly cites congressional intent, suggesting expanding the consideration of threshold level to other tangential issues such as MACT HAP controls also reducing criteria pollutant and ecological benefits of controls. Although such objectives may appear to be meritorious from an overall environmental protection perspective, there is no indication from the language of 112(d)(4) that other factors besides human health effects of specific threshold HAPs are intended to be considered.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 140

Comment: EPA has a great deal of latitude in exploring other ways to "consider threshold levels with ample margin of safety". Even though the MACT are primarily technology-based standards, the intent of section 112(d)(4) is to allow flexibility for EPA to establish special provisions for threshold HAPs that do not contribute significant health risk. Here we provide a conceptual model of how an HBEL could be incorporated into the Boiler MACT.

Following the approach of the Health Based Compliance Alternative of the 2004 Boiler MACT rule, HBELs could either be established through conservatively-derived look-up tables (Tier 1 HBEL) or a facility could develop a site-specific HBEL based on modeling following EPA guidance (EPA, 2004) (Tier 2 HBEL). A facility would need to certify through fuel analysis or source testing that its boiler emissions meet the corresponding HBEL. Alternatively, limits for HCl and other pollutants that are already established in a facility's air permit could be used in lieu of HBELs.
Toxicity Considerations in Developing HBELs
Because it is acknowledged that some of the HAPs subject to HBELs may have overlapping health effects, rather than considering only individual HAP exposure, the concept of Target

Organ Specific Hazard Index (TOSHI) following U.S. EPA Guidance (EPA 2004) may be appropriate in some instances. The hazard index concept inherently assumes that potential health effects due to simultaneous exposure are additive. [This method was applied in the 2004 Boiler MACT HBCA where the effects of Cl2 and HCl were assumed to be additive by computing HCl toxic equivalent emissions. Although not elaborated in these comments, it is inherently assumed, that this same or similar approach for combining effects of Cl2 and HCl effects is appropriate.]
As noted above, adding the health effects is appropriate for the acute health effects of the primary HAP acid gases from solid fuel industrial boilers, HCl, Cl2.and HF, and adding chronic effects of HCl and Cl2 is also appropriate. For instance, following the TOSHI concept, the development of acute HBELs for acid gases can consider combined emissions of HCl, Cl2and HF, and development of chronic HBELs can consider combined emissions HCl and Cl2 based on toxicity weighted emissions. In this case, an HCl acid gas toxicity-weighted short-term emission rate can be defined as the emission rate of HCl + the emission rate of Cl2 x Threshold of HCl /Threshold of Cl2 + the emission rate of HF x Threshold of HCl /Threshold of HF.
Establishment of separate chronic 112(d)(4) HBEL for HF and HCN is supported since the critical effect/target organ on which the chronic toxicity criteria are based is different for the two acid gases and the mechanism of action is different as well. Because Mn health effects and mechanisms of action can be differentiated from other HAPs, HBELs for Mn should be established independently.
Tier 1 HBELs – Based on Physical Parameters using Look-up Tables
The HBELs could take the form of a limited number of alternative HAP emissions limits that would be based on simple physical parameters related to dispersion. These limits would be set in such a way that there would be no health effects due to inhalation of specified threshold HAPs such as acid gases (primarily hydrogen chloride) and metals such as Mn.
EPA could develop Tier 1 HBELs based on screening-level dispersion modeling that conservatively relates maximum off-site concentrations associated with all Boiler MACT sources at a facility. A separate HBEL would apply to each facility based on the combination of physical stack parameters from each subject boiler.
The physical parameters incorporated into the screening-level modeling used to develop the tables should include the basic parameters that govern the dispersion and are. These include:
* Source characteristics, such as stack height and building height for each MACT source;

* Distance to property line;

* Maximum height of on-site structures;

* Presence of highest nearby terrain (e.g., within 5 km).
Tier 1 HBELs look-up tables would account for various combinations of these physical parameters. Because the look-up tables are based on screening-level dispersion models, such as SCREEN3 or AERSCREEN, that are designed to be conservative, this would provide the “ample margin of safety” as required by 112(d)(4). Thus, EPA can assure that compliance with the Tier 1 HBELs will mean that actual concentrations to which the public could be exposed are below established health effects threshold levels. The screening modeling that EPA would use to develop Tier 1 HBELs may address both chronic (annual average) and acute (maximum 1-hour) threshold effects, as appropriate. The determination of whether HBELs are appropriate for acute effects, chronic effects or both types of effects depends on whether an acute or chronic effect for

a threshold HAP is universally demonstrated to be more limiting. EPA may conclude, as it did in 2004, that protection against chronic health effects will inherently safeguard against acute health effects. An example of the possible structure of Tier 1 HBEL look-up tables is provided in Appendix H to these comments.

Tier 2 HBELs – Based on Site-specific Dispersion Modeling

If facility boiler emissions exceed the conservatively derived Tier 1 HBELs or if the regulatory agency judges that the physical layout or dispersion environment of the site make it inappropriate to apply the Tier 1 HBEL look-up tables, a facility would conduct site-specific dispersion modeling. Site specific modeling would use source specific stack parameters and apply EPA's state-of-the-science dispersion model AERMOD with five years of representative meteorological data. Model receptors could be placed at the boundary and in a specified grid representing off-site locations out to 5 km or could use site-specific receptor locations such as have been previously established for ambient air quality modeling.

In this modeling, the combined impact of the specific HBEL HAPs would be modeled for the appropriate averaging times (1-hour for acute and annual average for chronic) and compared to established health effects benchmarks, such as those provided in Section B, Table 1 of these comments. As noted, to address acute effects of acid gases, it is appropriate to add the hazard quotients (HQ) (modeled concentration divided by health effects threshold) for HCl, Cl_2, and HF to compute a hazard index (HI) for acute respiratory effects. A HI < 1.0 indicates that there is no incremental health effect. To address chronic effects of acid gases, it is appropriate to add the HQs (modeled concentration divided by health effects threshold) for HCl and Cl_2 to compute a hazard index (HI) for chronic respiratory effects. As noted, for chronic effects of HF, HCN and Mn it is appropriate to evaluate threshold effects separately for each pollutant. To establish HBELs for each boiler, the facility would use the modeling to determine the combination of peak 1-hour and annual average emission rates that result in a HI or HQ of 1.0. Thus, if emissions from each subject boiler are less than these site-specific HBELs it will be assured that exposure will not exceed health effects thresholds as required under CAA Section 112(d)(4).

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Timothy Hunt
Commenter Affiliation: American Forest and Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2002-0058-3213.1
Comment Excerpt Number: 142

Comment: In establishing compliance with HBELs, a facility will need to estimate upper-limit short-term emissions to assess acute threshold health effects and annual average emissions to assess chronic threshold effects. Realistic, yet conservative, HAP emission rate assumptions should be used in determining compliance with HBELs under 112(d)(4) rather than across-the-board worst-case assumptions because using worst-case emission assumptions will materially overestimate both chronic and acute risk. EPA contends that a reason not to include a risk option such as HBEL is that there is lack of available data for HAP emissions from boiler sources. Although care must be taken in estimating emissions, for the HAPs under consideration,

standardized methods could be established to develop suitably conservative emission estimates based either on fuel data or emission tests.
If fuel testing is used, emissions for HCl, Cl2, HF, and Mn may be conservatively estimated based on knowledge of fuel type, measured fuel concentrations and use rate, assuming 100% of the HAP is released to the atmosphere. If source testing is used it will automatically account for a degree of HAP removal through bottom ash, and emission controls. Because it is recognized that a single fuel sample or source test may not be representative of the long-term average, multiple fuel samples taken over an established period could be required. If a boiler has variable fuel sources,(e.g., coal from different mines or various types of wood), a number of samples from each source type would also be required. The variability of emissions would then be used following standardized data analysis methods to estimate the 95th percentile average emission factor to be used in the chronic HBEL compliance determination and combined with permitted annual fuel use. To account for short-term (hour-by hour) fluctuations the maximum hourly fuel use could be applied, along with a statistical estimate of the 95th percentile concentration for each HAP to estimate emissions for the acute HBEL.
This method of evaluating short-term fluctuations is highly conservative because the modeling used to develop the HBELs implicitly assumes that a source continuously emits each HAP at its 95th percentile maximum emission rate and that the worst-case emissions occur concurrently with worst-case dispersion conditions (Paine and Heinold 2010). The degree to which this highly conservative assumption affects HBEL certification depends on whether the acute HBEL or the chronic HBEL is limiting.
A similar procedure can be applied based on source test data. In the case where emission controls are in-place, the source could have the option of measuring uncontrolled or controlled emissions. If emission controls are used during the source test, additional parameters related to the control device would need to me monitored.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Ronald W. Gore
Commenter Affiliation: Alabama Department of Environmental Management
Document Control Number: EPA-HQ-OAR-2002-0058-2465.1
Comment Excerpt Number: 5

Comment: While the purpose of the MACT regulations is to reduce health impacts from Hazardous Air Pollutants, the "eliminate emissions at any cost" strategy that EPA is utilizing in establishing these MACTs has no correlation to actual health impacts. In fact, with the exception of Hg, HCI, and dioxin/furans, these proposed regulations do not establish limitations on any HAPs but instead draw on generalized correlations to criteria air pollutants for which standards are proposed. In effect, EPA is establishing limitations for pollutants regulated under other sections of the Clean Air Act; limitations which could not be justified otherwise. Therefore, Health Based Compliance Alternatives similar to those included in the prior version of the Agency's boiler MACT should be included. It would likely be determined that many small to moderate size boilers have little to no health-based impacts from their HAP emissions, rendering the addition of costly emissions controls unnecessary.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Lewis F. Gossett
Commenter Affiliation: South Carolina Manufacturers Alliance
Document Control Number: EPA-HQ-OAR-2002-0058-2602.1
Comment Excerpt Number: 5

Comment: EPA needs to look at alternatives that protect public health at a more reasonable cost. EPA has the discretion needed to set a more reasonable rule.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Walter Tyler
Commenter Affiliation: Invista
Document Control Number: EPA-HQ-OAR-2002-0058-2761.1
Comment Excerpt Number: 17

Comment: Similar to the HBCA approach, EPA previously had included the Total Selected Metals (TSM) compliance alternative. INVISTA recommends that EPA also includes this, or a similar approach, in the final Boiler MACT regulation.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Robert R. Perry
Commenter Affiliation: Citizen
Document Control Number: EPA-HQ-OAR-2002-0058-2753
Comment Excerpt Number: 1

Comment: The ICI Major Source Boilers rules in present form are overly stringent and in need of revision. I encourage EPA to rewrite these rules using a health based risk assessment. This approach will allow the rules to be no more stringent than what is need to protect human health.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Susan J. Miller
Commenter Affiliation: Brick Industry Association
Document Control Number: EPA-HQ-OAR-2002-0058-2716.1

Comment Excerpt Number: 7

Comment: Particularly in these tough economic times, EPA should embrace standards that both provide the same HAP benefits while greatly reducing costs. Section 112(d)(4) allows EPA to establish these alternative standards that have clearly demonstrated both their ability to be protective of the environment and far less costly than EPA's proposed approach. After all of the years EPA has had to develop these standards, and all of the data that have been submitted to EPA, EPA should evaluate establishing these alternative and equivalent standards.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Russ A. Wozniak
Commenter Affiliation: Dow Chemical Company
Document Control Number: EPA-HQ-OAR-2002-0058-2632.1
Comment Excerpt Number: 69

Comment: EPA notes that it would need additional facility-specific emissions information to develop model plants for the eleven subcategories considered in the proposed rule. This would allow EPA to conduct the dispersion modeling necessary to establish health-based emission limits. EPA should instead establish a process where EPA publishes target health-based concentration based limits (annual average concentrations and/or hourly average concentrations, if needed). EPA should then require the owner/operator to perform dispersion modeling studies to predict the maximum off-site concentrations of these HAPs or perhaps of HCl if used as a surrogate for the other air contaminants. This type of approach would place the work of conducting the dispersion modeling on the owner/operator and then state agencies and/or EPA could review the studies and issue a final determination of whether or not the HBCA criteria is met.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 5

Comment: The proposed standards are far more stringent than needed to assure protection of health and the environment from industrial boiler HAP emissions. EPA has significantly underestimated the cost and burden to industry of the proposed rule.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Robert R. Perry
Commenter Affiliation: FirstEnergy Generation Corp
Document Control Number: EPA-HQ-OAR-2002-0058-2772.1
Comment Excerpt Number: 7

Comment: EPA should utilize a "health-based" approach under Clean Air Act 112(d)(4) in establishing ICI Boiler MACT emission limits. EPA should utilize a "health-based" approach, where possible, in establishing HAP emission control requirements for ICI Boilers. Once ICI Boilers control HAPs to a level protecting public health, with an ample margin of safety, no further reduction in HAPs should be necessary or required.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Chris Korleski
Commenter Affiliation: Ohio EPA
Document Control Number: EPA-HQ-OAR-2002-0058-2818.1
Comment Excerpt Number: 8

Comment: Carefully examine approaches that reduce costs without affecting public health.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Traylor Champion
Commenter Affiliation: Georgia-Pacific LLC
Document Control Number: EPA-HQ-OAR-2002-0058-2745.1
Comment Excerpt Number: 11

Comment: An HBCA can be implemented as described in the vacated Boiler MACT rule. In the original 2004 Boiler MACT rule, EPA set forth a comprehensive procedure for sources to implement the requirements of an HBCA-based emission limit. These procedures consisted of look-up tables as a screening tool for facilities to easily determine if their HBCA would be applicable to the specific location. As an alternate to the look-up tables, facilities could perform a site specific risk assessment using state-approved air dispersion models. GP supports a similar approach for this rulemaking.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Alicia Oman
Commenter Affiliation: National Association of Manufacturers

Document Control Number: EPA-HQ-OAR-2002-0058-2845.1
Comment Excerpt Number: 72

Comment: While EPA has discretion in deciding whether to set HBELs under 112(d)(4), the Agency cannot be arbitrary and capricious in making such a decision. The proposed HCl and PM emissions limitations for all types of industrial boilers are exceedingly stringent. Affected sources will have to spend tens of millions of dollars in order to meet the standards and, as even EPA predicts, a significant number of existing units simply will not be able to meet the standards and will be required to shut down. In addition, the work that EPA performed in support of the HBELs included in the 2004 rule demonstrates that the proposed standards are far more stringent than needed to assure the protection of public health with an ample margin of safety. The costs and burdens on affected sources and the degree of control needed to provide adequate health and environmental protection are both key factors that should be considered by the Agency in deciding whether to adopt HBELs in the Industrial Boiler MACT.

In the proposed rule, EPA completely ignores these factors. The Agency's discussion of HBELs includes no assessment whatsoever of the costs that might be avoided by adopting HBELs for HCl or manganese. As to potential effects on health or environment, EPA simply raises implementation questions and asserts a lack of information to resolve the questions. Such an approach is facially inadequate in light of the extensive policy, scientific, and technical assessment developed in support of the HBELs in the 2004 Industrial Boiler MACT standard. In short, EPA's failure to fully consider key factors that are relevant to making an informed decision as to whether HBELs should be adopted is arbitrary and capricious.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Commenter Name: Alicia Oman
Commenter Affiliation: National Association of Manufacturers
Document Control Number: EPA-HQ-OAR-2002-0058-2845.1
Comment Excerpt Number: 73

Comment: EPA asserts in the proposed rule that its decision to not propose HBELs "is not contrary to EPA's prior decisions where we found it appropriate to exercise the discretion to invoke the authority in section 112(d)(4) for HCl, since the circumstances in this case differ from previous considerations." 75 Fed. Reg. 32032. In contrast to "other source categories for which EPA has exercised its authority under section 112(d)(4)," EPA explains that boilers and process heaters are more likely to be co-located with other HAP sources and are often located in heavily populated urban areas where many other HAP sources exist. Id. The Agency concludes that, "These factors make an analysis of the health impact of emissions from these sources on the exposed population significantly more complex than for many other source categories, and therefore make it more difficult to establish an ample margin of safety." Id.

These assertions fail to reflect the fact that the industrial boiler source category is one of the few categories where EPA has previously "found it appropriate to exercise the discretion to invoke the authority in section 112(d)(4).” Id. As a result, EPA has already drawn conclusions as to how to deal with possible co-location with other HAP sources and how to appropriately consider HAP emissions from other nearby sources. These are not issues of first impression generally or in the specific context of industrial boilers and process heaters. The questions have been asked and answered in 2004 in the context of notice and comment rulemaking for the industrial boiler and process heater source category.

Thus, EPA is mistaken in asserting that its decision not to propose HBELs is “not contrary to EPA’s prior decisions.” Id. The decision not to propose HBELs is flatly inconsistent with EPA’s prior determination that HBELs are appropriate and justified for the industrial boiler and process heater source category. EPA’s failure to acknowledge its prior determination and failure to explain why it has raised as questions issues that previously were resolved (such as how to consider co-located HAP sources and nearby HAP sources) render its decision not to propose HBELs arbitrary and capricious.

Response: See preamble for response to final decision on Health Based Compliance Alternative.

Other

Other – Merging of Phase I and Phase II Test Data

Commenter Name: Jim Griffin
Commenter Affiliation: American Chemistry Council
Document Control Number: EPA-HQ-OAR-2002-0058-2792.1
Comment Excerpt Number: 25

Comment: The most critical shortcoming in EPA’s data analysis is the merging of test results reported by Phase I ICR respondents with results from the Phase II mandatory test program into a single database. This database was used to identify "best performers" in each subcategory and calculate proposed emission limits. In merging the test results from Phase I and Phase II, EPA implicitly assumed the data were comparable without conducting a detailed review of the actual stack sampling protocol and associated laboratory analysis reports.

EPA issued a set of instructions for the Phase II ICR testing program. These instructions covered: the sampling methods to be used; minimum sampling volumes for different pollutants; how non-detect values should be handled and reported; how boiler heat input rates should be calculated; and the data reporting and submission procedures, i.e., required use of EPA’s Electronic Reporting Tool (ERT).24 The instructions were silent on how method detection limits should be determined, and the methods themselves do not address detection limits.

The initial instructions distributed to the facilities selected by EPA for sampling contained a number of unclear or ambiguous requirements, which necessitated six subsequent Q&A and guidance documents and an EPA webinar to clarify what EPA really wanted. Unfortunately, since EPA set a four month time frame for the tests to be performed and results to be submitted to EPA, many companies had already contracted with stack sampling firms and had an agreed-upon scope of work before EPA had made final clarifications to the instructions. Thus, it appears that not all of the Phase II stack testing was conducted in accordance with EPA's final instructions and guidance.

Emission tests not conducted as part of the Phase II ICR would not have satisfied all of the criteria established by EPA. For example, the handling and reporting of non-detects were different because EPA stack testing methods are silent on these points. However, this is a critical issue when comparing emission test results to identify units with the lowest emission rates.

Response: EPA acknowledges the concerns of the commenter about merging test data. In the final emission test database we flag the source of the emission test data as either Phase I or Phase II, or other voluntary data submittal so that stakeholders can identify the source of the data. Given the large affected source category and comments from many others that suggest the current combined dataset is insufficiently representative, we believe it is inappropriate to only use data submitted from the Phase II ICR for the basis of the standard. We have also reviewed and updated several ICR Phase I test results from the best performing units in order to reduce the inconsistent treatment of mercury fractions and detection limits, as time allowed.

Appendix A: Commenter Tables

The following 3 tables detail all of the comments received by EPA in response to Proposed Rule published in the Federal Register on June 4, 2010 at 75 FR 31895, *National Emission Standards for Hazardous Air Pollutants for Major Source Industrial/Commercial/Institutional Boilers and Process Heaters.*

Table 1 is the comprehensive list, by Document Control Number (DCN), the number assigned by the EPA docket center to identify each document in the docket.

Table 2 displays the number of form letters submitted to EPA-HQ-OAR-2002-0058. "Form Letter Group" is the description given to a form letter based on the industry or non-governmental organization that coordinated the comment effort. The number in parentheses after the Form Letter Group is the number of identical letters received for each form letter group.

Table 3 identifies comments that specifically reference other comment letters written in response to this proposed rule or incorporated by reference another comment written in response to this proposed rule, effectively supporting some or all of the opinions expressed by another commenter.

Document ID	Document Title
EPA-HQ-OAR-2002-0058-0838.1	George Woods, Littlejohn Engineering Associates
EPA-HQ-OAR-2002-0058-0840.1	B. Machaver
EPA-HQ-OAR-2002-0058-0841.1	Brian Swanson, President and General Manager, CMC Solutions and CMC Support
EPA-HQ-OAR-2002-0058-0843	T. Lovgren
EPA-HQ-OAR-2002-0058-0844.1	Regina Henry, Senior Environmental Manager, Cemex Inc. USA
EPA-HQ-OAR-2002-0058-0845	Mass Comment Campaign sponsored by Credo (6696)
EPA-HQ-OAR-2002-0058-0846.1	Theresa Pugh, Director, Environmental Services, American Public Power Association (APPA)
EPA-HQ-OAR-2002-0058-0847.1	Peter Maki
EPA-HQ-OAR-2002-0058-0848.1	Craig Clapsaddle
EPA-HQ-OAR-2002-0058-0849.1	Ritchie Monteith
EPA-HQ-OAR-2002-0058-0850	S. Hao
EPA-HQ-OAR-2002-0058-0851.1	Michael Todd, American Petroleum Institute (API) and David Friedman, National Petrochemical and Refiners Association (NPRA)
EPA-HQ-OAR-2002-0058-0852.1	Sarah S. Markham, Environmental Engineer, Research & Environmental Affairs, Southern Company
EPA-HQ-OAR-2002-0058-0853	Dale Herendeen, Environmental Manager, AbitibiBowater
EPA-HQ-OAR-2002-0058-0854.1	Norbord Industries
EPA-HQ-OAR-2002-0058-0855.1	John Huffman, ChemTreat, Inc.
EPA-HQ-OAR-2002-0058-0856.1	Dwayne Arino, Director, Environmental Engineering, JELD-WEN, Inc.
EPA-HQ-OAR-2002-0058-0857	Mass Comment Campaign sponsored by Sierra Club (1300)
EPA-HQ-OAR-2002-0058-0858	J. Melloh
EPA-HQ-OAR-2002-0058-0859	J. Byerley
EPA-HQ-OAR-2002-0058-0860	J. Jackman
EPA-HQ-OAR-2002-0058-0861	A. Grabbe
EPA-HQ-OAR-2002-0058-0862	B. Baggs
EPA-HQ-OAR-2002-0058-0863	B. Berger
EPA-HQ-OAR-2002-0058-0864	C. Tansey
EPA-HQ-OAR-2002-0058-0865	C. Weingeist
EPA-HQ-OAR-2002-0058-0866	J. Lamberty
EPA-HQ-OAR-2002-0058-0867	J. Bajorek
EPA-HQ-OAR-2002-0058-0868	J. Fisk
EPA-HQ-OAR-2002-0058-0869	J. Karches
EPA-HQ-OAR-2002-0058-0870	J. Mayeux
EPA-HQ-OAR-2002-0058-0871	J. and J. Kyler
EPA-HQ-OAR-2002-0058-0872	A. Griffin
EPA-HQ-OAR-2002-0058-0873	J. Andes
EPA-HQ-OAR-2002-0058-0874	B. Aliriza
EPA-HQ-OAR-2002-0058-0875	B. Schaible
EPA-HQ-OAR-2002-0058-0876	C. Goldwater
EPA-HQ-OAR-2002-0058-0877	C. Scott
EPA-HQ-OAR-2002-0058-0878	C. Vidmar
EPA-HQ-OAR-2002-0058-0879	D. Clayton
EPA-HQ-OAR-2002-0058-0880	E. Struthers
EPA-HQ-OAR-2002-0058-0881	C. Mark
EPA-HQ-OAR-2002-0058-0882	C. Laing
EPA-HQ-OAR-2002-0058-0883	E. Keiter
EPA-HQ-OAR-2002-0058-0884	E. Anderson
EPA-HQ-OAR-2002-0058-0885	E. Dale
EPA-HQ-OAR-2002-0058-0886	E. Withers
EPA-HQ-OAR-2002-0058-0887	F. Pilholski
EPA-HQ-OAR-2002-0058-0888	A. Rhoads
EPA-HQ-OAR-2002-0058-0889	C. Barron
EPA-HQ-OAR-2002-0058-0890	A. Kellum
EPA-HQ-OAR-2002-0058-0891	D. Logue
EPA-HQ-OAR-2002-0058-0892	D. Tarr
EPA-HQ-OAR-2002-0058-0893	G. Simpson
EPA-HQ-OAR-2002-0058-0894	G. Warren
EPA-HQ-OAR-2002-0058-0895	G. Michaels

Document ID	Document Title
EPA-HQ-OAR-2002-0058-0896	D. Barnt
EPA-HQ-OAR-2002-0058-0897	K. Floyd
EPA-HQ-OAR-2002-0058-0898	D. Rehner
EPA-HQ-OAR-2002-0058-0899	D. Leo
EPA-HQ-OAR-2002-0058-0900	W. McHenry
EPA-HQ-OAR-2002-0058-0901	T. Lotus
EPA-HQ-OAR-2002-0058-0902	D. Johnson
EPA-HQ-OAR-2002-0058-0903	K. Ryan
EPA-HQ-OAR-2002-0058-0904	K. Mason
EPA-HQ-OAR-2002-0058-0905	D. Jizi
EPA-HQ-OAR-2002-0058-0906	L. Stetzler
EPA-HQ-OAR-2002-0058-0907	L. Kitchel and L. Kitchel
EPA-HQ-OAR-2002-0058-0908	L. Sanchez
EPA-HQ-OAR-2002-0058-0909	L. Diament-Hansen
EPA-HQ-OAR-2002-0058-0910	S. Mcglothlin
EPA-HQ-OAR-2002-0058-0911	K. Querner
EPA-HQ-OAR-2002-0058-0912	N. Bartol
EPA-HQ-OAR-2002-0058-0913	R. Odgers
EPA-HQ-OAR-2002-0058-0914	D. Claitor
EPA-HQ-OAR-2002-0058-0915	K. Lee
EPA-HQ-OAR-2002-0058-0916	N. Neau
EPA-HQ-OAR-2002-0058-0917	L. Nicholas
EPA-HQ-OAR-2002-0058-0918	L. Hartmark
EPA-HQ-OAR-2002-0058-0919	L. Gonzalez
EPA-HQ-OAR-2002-0058-0920	M. Greer
EPA-HQ-OAR-2002-0058-0921	M. Carbone
EPA-HQ-OAR-2002-0058-0922	M. Hansen
EPA-HQ-OAR-2002-0058-0923	M. Nochimson
EPA-HQ-OAR-2002-0058-0924	M. Walters
EPA-HQ-OAR-2002-0058-0925	B. Ensor
EPA-HQ-OAR-2002-0058-0926	J. Davis
EPA-HQ-OAR-2002-0058-0927	A. Vatsky
EPA-HQ-OAR-2002-0058-0928	P. Williams
EPA-HQ-OAR-2002-0058-0929	J. McCloskey
EPA-HQ-OAR-2002-0058-0930	M. Willis
EPA-HQ-OAR-2002-0058-0931	L. Allen-Tawes
EPA-HQ-OAR-2002-0058-0932	M. Shays
EPA-HQ-OAR-2002-0058-0933	M. Rose
EPA-HQ-OAR-2002-0058-0934	A. Leigh
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EPA-HQ-OAR-2002-0058-1651	S. Petersen
EPA-HQ-OAR-2002-0058-1652	S. and B. Schmidt
EPA-HQ-OAR-2002-0058-1653	S. Blain
EPA-HQ-OAR-2002-0058-1654	D. Luckens
EPA-HQ-OAR-2002-0058-1655	M. Kiss
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EPA-HQ-OAR-2002-0058-1658	N. Stecker
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EPA-HQ-OAR-2002-0058-1666	A. Byrne
EPA-HQ-OAR-2002-0058-1667	J. King
EPA-HQ-OAR-2002-0058-1668	A. Flavelle
EPA-HQ-OAR-2002-0058-1669	A. Goodenough
EPA-HQ-OAR-2002-0058-1670	N. Akerley
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EPA-HQ-OAR-2002-0058-1689	R. Lewis
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EPA-HQ-OAR-2002-0058-1696	R. Moore
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EPA-HQ-OAR-2002-0058-1716	L. Marko
EPA-HQ-OAR-2002-0058-1717	A. Dor
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EPA-HQ-OAR-2002-0058-1719	N. Stevens
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EPA-HQ-OAR-2002-0058-1727	G. D'Souza
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EPA-HQ-OAR-2002-0058-1733	S. Davis
EPA-HQ-OAR-2002-0058-1734	S. and D. Whitmarsh
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EPA-HQ-OAR-2002-0058-1745	J. Greenstein
EPA-HQ-OAR-2002-0058-1746	L. Busche
EPA-HQ-OAR-2002-0058-1747	I. Marks
EPA-HQ-OAR-2002-0058-1748	P. Doyle
EPA-HQ-OAR-2002-0058-1749	P. Converse
EPA-HQ-OAR-2002-0058-1750	P. Bourgeois
EPA-HQ-OAR-2002-0058-1751	P. Comstock
EPA-HQ-OAR-2002-0058-1752	P. Curia
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EPA-HQ-OAR-2002-0058-1754.1	A. Hoffman
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EPA-HQ-OAR-2002-0058-1757	M. Reese-Upton
EPA-HQ-OAR-2002-0058-1758	Charles Thomas III, Shuqualak Lumber Co., Inc.
EPA-HQ-OAR-2002-0058-1759	L. Church
EPA-HQ-OAR-2002-0058-1760	T. Loy
EPA-HQ-OAR-2002-0058-1761	D. Nasser
EPA-HQ-OAR-2002-0058-1762	A. Plagge
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EPA-HQ-OAR-2002-0058-1799	S. Fontana
EPA-HQ-OAR-2002-0058-1800	R. Troopin
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EPA-HQ-OAR-2002-0058-1802	A. Myrick
EPA-HQ-OAR-2002-0058-1803	C. Jacobs
EPA-HQ-OAR-2002-0058-1804	M. Nochimson
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EPA-HQ-OAR-2002-0058-1812	W. Ebersberger
EPA-HQ-OAR-2002-0058-1813	V. Katz
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EPA-HQ-OAR-2002-0058-1815	C. Everett
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EPA-HQ-OAR-2002-0058-1842	M. DeLoye
EPA-HQ-OAR-2002-0058-1843	E. Mirabella
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EPA-HQ-OAR-2002-0058-1845	Caroline Dauzat, Owner, Rex Lumber
EPA-HQ-OAR-2002-0058-1846	Charles McRae, Owner, Rex Lumber
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EPA-HQ-OAR-2002-0058-1856	J. Nichols
EPA-HQ-OAR-2002-0058-1857	A. Bonvouloir
EPA-HQ-OAR-2002-0058-1858	R. Ruggles
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EPA-HQ-OAR-2002-0058-1860	A. Moffat
EPA-HQ-OAR-2002-0058-1861	S. Baudo
EPA-HQ-OAR-2002-0058-1862	B. Fitzpatrick
EPA-HQ-OAR-2002-0058-1863	M. Shimizu
EPA-HQ-OAR-2002-0058-1864	M. Weimer
EPA-HQ-OAR-2002-0058-1865	J. McCreary
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EPA-HQ-OAR-2002-0058-1867.1	Carl Johnson, Executive Director, Southern Pressure Treaters' Association
EPA-HQ-OAR-2002-0058-1868.1	David L. Meeker, Senior Vice President, Scientific Services, National Renderers Association (NRA)
EPA-HQ-OAR-2002-0058-1869.1	Randolph S. Price, Vice President, Environment, Health and Safety, Consolidated Edison of New York, Inc. (CEONY)
EPA-HQ-OAR-2002-0058-1870	Thomas C. Ludlow, Vice President and Chief Financial Officer, JWTR, LLC
EPA-HQ-OAR-2002-0058-1871	George Woods, Littlejohn Engineering Associates
EPA-HQ-OAR-2002-0058-1872	Casey Tommaro, Electrician, Sappi Fine Paper
EPA-HQ-OAR-2002-0058-1873	Gerald G. Brouillette, HSSE Manager, Shell Chemical LP (Shell) (Geismar, Louisiana)
EPA-HQ-OAR-2002-0058-1874	Steven D. Swanson, President/CEO, Swanson Group, Inc.
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EPA-HQ-OAR-2002-0058-1879	Fred L. Taylor, II, President, Troy Lumber Company
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EPA-HQ-OAR-2002-0058-1881.1	D. M. Porter
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EPA-HQ-OAR-2002-0058-1887	A. Abdalian
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EPA-HQ-OAR-2002-0058-1908	B. Hughes
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EPA-HQ-OAR-2002-0058-1913.1	John Williams, President, Maine Pulp & Paper Association (MPPA)
EPA-HQ-OAR-2002-0058-1914	B. Pratt
EPA-HQ-OAR-2002-0058-1915	M. Gargiulo
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EPA-HQ-OAR-2002-0058-1935	J. Pockrus
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EPA-HQ-OAR-2002-0058-1937	K. Weller-Coffman
EPA-HQ-OAR-2002-0058-1938	K. De Vier
EPA-HQ-OAR-2002-0058-1939	L. C. B. Stranaghan
EPA-HQ-OAR-2002-0058-1940	E. O'Dea
EPA-HQ-OAR-2002-0058-1941	L. Weiner
EPA-HQ-OAR-2002-0058-1942	L. Bagley
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EPA-HQ-OAR-2002-0058-1946	W. Montgomery
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EPA-HQ-OAR-2002-0058-1948	M. Volkman
EPA-HQ-OAR-2002-0058-1949	C. Speas
EPA-HQ-OAR-2002-0058-1950	M. Shuter
EPA-HQ-OAR-2002-0058-1951	R. McBane
EPA-HQ-OAR-2002-0058-1952	M. Walton
EPA-HQ-OAR-2002-0058-1953	M. Miller
EPA-HQ-OAR-2002-0058-1954	M. Haugen
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EPA-HQ-OAR-2002-0058-1960	D. Millett
EPA-HQ-OAR-2002-0058-1961	C. Davies
EPA-HQ-OAR-2002-0058-1962	F. Schilling
EPA-HQ-OAR-2002-0058-1963	R. Caputo
EPA-HQ-OAR-2002-0058-1964	R. Gale
EPA-HQ-OAR-2002-0058-1965	C. Hall
EPA-HQ-OAR-2002-0058-1966	C. and C. Gartland
EPA-HQ-OAR-2002-0058-1967	D. Slater
EPA-HQ-OAR-2002-0058-1968	D. Weise
EPA-HQ-OAR-2002-0058-1969	E. Powell
EPA-HQ-OAR-2002-0058-1970	D. Stanko
EPA-HQ-OAR-2002-0058-1971	E. Kompanek
EPA-HQ-OAR-2002-0058-1972	R. Jenkinson
EPA-HQ-OAR-2002-0058-1973	R. Kofler
EPA-HQ-OAR-2002-0058-1974	R. Yarnell
EPA-HQ-OAR-2002-0058-1975.1	Randy Stoeckel, Vice President, Johnson Timber Corporation
EPA-HQ-OAR-2002-0058-1976	David Church, Longview Fibre Paper and Packaging
EPA-HQ-OAR-2002-0058-1977	J. Koss
EPA-HQ-OAR-2002-0058-1978	J. Ahearn
EPA-HQ-OAR-2002-0058-1979	J. Hamann
EPA-HQ-OAR-2002-0058-1980	J. Butler
EPA-HQ-OAR-2002-0058-1981	J. Hartman
EPA-HQ-OAR-2002-0058-1982	J. Franklin
EPA-HQ-OAR-2002-0058-1983	J. Phillips
EPA-HQ-OAR-2002-0058-1984	A. Cheng
EPA-HQ-OAR-2002-0058-1985	K. Williams
EPA-HQ-OAR-2002-0058-1986	J. Perez
EPA-HQ-OAR-2002-0058-1987	K. Vasko
EPA-HQ-OAR-2002-0058-1988	L. S. Miller
EPA-HQ-OAR-2002-0058-1989	H. McKinney
EPA-HQ-OAR-2002-0058-1990	M. A. Lajoie-Sandroff
EPA-HQ-OAR-2002-0058-1991	M. Star
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Document ID	Document Title
EPA-HQ-OAR-2002-0058-2349.1	Ardis Almond, PE, President, Almond Brothers Lumber Company
EPA-HQ-OAR-2002-0058-2350.1	Thomas Ratzlaff, Mayor, City of Park Falls, Wiconsin
EPA-HQ-OAR-2002-0058-2351.1	R. Wade Mosby, Senior Vice President, The Collins Companies
EPA-HQ-OAR-2002-0058-2352	Don Grimm, Hood Industries, Inc.
EPA-HQ-OAR-2002-0058-2353.1	Troy Runge, Director, Wisconsin BioEnergy Initiative (WBI)
EPA-HQ-OAR-2002-0058-2354	B. Coulson
EPA-HQ-OAR-2002-0058-2355	M. Schwartz
EPA-HQ-OAR-2002-0058-2356	D. Duda
EPA-HQ-OAR-2002-0058-2357	E. Spalding
EPA-HQ-OAR-2002-0058-2358	C. Holland
EPA-HQ-OAR-2002-0058-2359	K. McCoy
EPA-HQ-OAR-2002-0058-2360	W. Neill
EPA-HQ-OAR-2002-0058-2361	R. Flory
EPA-HQ-OAR-2002-0058-2362	P. Kerman
EPA-HQ-OAR-2002-0058-2363	J. Kennedy
EPA-HQ-OAR-2002-0058-2364	L. Burlingame
EPA-HQ-OAR-2002-0058-2365	T. Watts
EPA-HQ-OAR-2002-0058-2366	G. Boyer
EPA-HQ-OAR-2002-0058-2367	E. Ball
EPA-HQ-OAR-2002-0058-2368	M. Leven
EPA-HQ-OAR-2002-0058-2369	G. Taylor
EPA-HQ-OAR-2002-0058-2370	J. Taylor
EPA-HQ-OAR-2002-0058-2371	T. Jackson
EPA-HQ-OAR-2002-0058-2372	W. and P. Talbert
EPA-HQ-OAR-2002-0058-2373	J. Lynch
EPA-HQ-OAR-2002-0058-2374	T. L. Hamzy
EPA-HQ-OAR-2002-0058-2375	M. Kohn
EPA-HQ-OAR-2002-0058-2376	T. Hazelleaf
EPA-HQ-OAR-2002-0058-2377	J. Marsh
EPA-HQ-OAR-2002-0058-2378	J. Thacker
EPA-HQ-OAR-2002-0058-2379	C. Lavelle-pahl
EPA-HQ-OAR-2002-0058-2380	H. Curtler III
EPA-HQ-OAR-2002-0058-2381	P. Brownlee
EPA-HQ-OAR-2002-0058-2382.1	Ashley B. Peterson, Ph.D., Director, Regulatory Affairs, American Meat Institute (AMI)
EPA-HQ-OAR-2002-0058-2383.1	Bill Wickman and Laurel Brent-Bumb, Representatives, Sustainable Forest Action Coalition (SFAC)
EPA-HQ-OAR-2002-0058-2384.1	Steven Jarvis, Executive Director, Missouri Forest Products Association (MFPA)
EPA-HQ-OAR-2002-0058-2385	Richard Holland, Environmental Manager, Packaging Corporation of America (PCA)
EPA-HQ-OAR-2002-0058-2386.1	Michael J. Hagenbarth, Director, Environmental, Health and Safety, Rock Tenn Company
EPA-HQ-OAR-2002-0058-2387	Claude Audet, Vice President and Chief Operating Officer, Biomass, Boralex Inc.
EPA-HQ-OAR-2002-0058-2387.1	Claude Audet, Vice President and Chief Operating Officer, Biomass, Boralex Inc.
EPA-HQ-OAR-2002-0058-2388.1	Kerry R. Flick, General Manager, Technology, Metso Power
EPA-HQ-OAR-2002-0058-2389	C. Lynt
EPA-HQ-OAR-2002-0058-2390	S. Futrell
EPA-HQ-OAR-2002-0058-2391	V. Terry
EPA-HQ-OAR-2002-0058-2392	C. Mead
EPA-HQ-OAR-2002-0058-2393	F. Buncik
EPA-HQ-OAR-2002-0058-2394	S. Flick
EPA-HQ-OAR-2002-0058-2395	L. Church
EPA-HQ-OAR-2002-0058-2396	S. Darby
EPA-HQ-OAR-2002-0058-2397	R. and L. Macomber
EPA-HQ-OAR-2002-0058-2398	L. Garcia
EPA-HQ-OAR-2002-0058-2399	M. Green
EPA-HQ-OAR-2002-0058-2400	M. Mukherjee
EPA-HQ-OAR-2002-0058-2401	P. Gollon
EPA-HQ-OAR-2002-0058-2402.1	Randy Bush, President, Virginia Forest Products Association (VFPA)
EPA-HQ-OAR-2002-0058-2403.1	Robert Karwowski, Director, Environmental, Health & Safety Programs, North American Region, Whirlpool Corporation

Document ID	Document Title
EPA-HQ-OAR-2002-0058-2404.1	Preston Carpenter, Vice President, Carpenters Pole & Piling Company, Inc.
EPA-HQ-OAR-2002-0058-2405	K. Keating
EPA-HQ-OAR-2002-0058-2406	R. Meier
EPA-HQ-OAR-2002-0058-2407	S. Stevenson
EPA-HQ-OAR-2002-0058-2408	J. Pisano
EPA-HQ-OAR-2002-0058-2409	J. Gintzler
EPA-HQ-OAR-2002-0058-2410	D. Randall
EPA-HQ-OAR-2002-0058-2411	A. Pillai
EPA-HQ-OAR-2002-0058-2412	P. Ewing
EPA-HQ-OAR-2002-0058-2413	S. Christiansen
EPA-HQ-OAR-2002-0058-2414.1	Kevin Bilbrey, President, Clarke County Pole & Piling Co., Inc.
EPA-HQ-OAR-2002-0058-2415	K. Woods
EPA-HQ-OAR-2002-0058-2416	G. Anderson
EPA-HQ-OAR-2002-0058-2417.1	John M. Cullen, Director, Health, Safety & Environmental Affairs, Masco Corporation
EPA-HQ-OAR-2002-0058-2418.1	Joe O'Rourke, Plant Manager, F. H. Stoltze Land & Lumber Co.
EPA-HQ-OAR-2002-0058-2419	Thomas J. Temple, Vice President Wood Products, Potlatch Corporation
EPA-HQ-OAR-2002-0058-2420	R. Hanville
EPA-HQ-OAR-2002-0058-2421	J. Basralian
EPA-HQ-OAR-2002-0058-2422	M. Porubcan
EPA-HQ-OAR-2002-0058-2423	T. Eddy
EPA-HQ-OAR-2002-0058-2424	M. Wolfe
EPA-HQ-OAR-2002-0058-2425	S. Li
EPA-HQ-OAR-2002-0058-2426	E. Essman
EPA-HQ-OAR-2002-0058-2427	L. Sarhage
EPA-HQ-OAR-2002-0058-2428	N. Kingston
EPA-HQ-OAR-2002-0058-2429	J. Cassidy
EPA-HQ-OAR-2002-0058-2430	M. Rice
EPA-HQ-OAR-2002-0058-2431	L. Callio
EPA-HQ-OAR-2002-0058-2432	G. Gustafson
EPA-HQ-OAR-2002-0058-2433	R. Nunno
EPA-HQ-OAR-2002-0058-2434	R. and L. Lockwood
EPA-HQ-OAR-2002-0058-2435	T. Gerrodette
EPA-HQ-OAR-2002-0058-2436	L. Sturm
EPA-HQ-OAR-2002-0058-2437	R. Valdez
EPA-HQ-OAR-2002-0058-2438	G. Epailly
EPA-HQ-OAR-2002-0058-2439	C. Watson
EPA-HQ-OAR-2002-0058-2440	T. McLachlan
EPA-HQ-OAR-2002-0058-2441	G. Loveday
EPA-HQ-OAR-2002-0058-2442	V. Russell
EPA-HQ-OAR-2002-0058-2443	T. Mason
EPA-HQ-OAR-2002-0058-2444	T. Valentin
EPA-HQ-OAR-2002-0058-2445	V. Morehead
EPA-HQ-OAR-2002-0058-2446	T. Hall
EPA-HQ-OAR-2002-0058-2447	C. Thompson
EPA-HQ-OAR-2002-0058-2448	J. Fritz
EPA-HQ-OAR-2002-0058-2449	M. Dillon
EPA-HQ-OAR-2002-0058-2450	J. Applebaum
EPA-HQ-OAR-2002-0058-2451	L. Green
EPA-HQ-OAR-2002-0058-2452.1	Jay Galloway, President, Tolleson Lumber Company
EPA-HQ-OAR-2002-0058-2453	T. Duffy
EPA-HQ-OAR-2002-0058-2454	R. Waller
EPA-HQ-OAR-2002-0058-2455	J. Pence
EPA-HQ-OAR-2002-0058-2456	J. Carlsen
EPA-HQ-OAR-2002-0058-2457	S. Gallucci
EPA-HQ-OAR-2002-0058-2458	L. Bryant
EPA-HQ-OAR-2002-0058-2459	A. Kurland

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EPA-HQ-OAR-2002-0058-2460	P. M. Thomas
EPA-HQ-OAR-2002-0058-2461.1	Jeanine Bourgard, Flambeau River Papers, Park Falls, Wisconsin
EPA-HQ-OAR-2002-0058-2462.1	John M. Cullen, Director, Health and Environmental Affairs, Masco Corporation
EPA-HQ-OAR-2002-0058-2463	Randolph Price, Vice President Environment, Health & Safety, Consolidated Edison Company of New York, Inc. (conEdison)
EPA-HQ-OAR-2002-0058-2464	Frederick G. Heath, Vice President, Brown Wood Preserving Co., Inc
EPA-HQ-OAR-2002-0058-2465.1	Ronald W. Gore, Chief, Air Division, Alabama Department of Environmental Management (ADEM)
EPA-HQ-OAR-2002-0058-2466.1	Michael Bradley, Director, The Clean Energy Group
EPA-HQ-OAR-2002-0058-2467.1	Tom Steiner, Controller, Flambeau River Papers
EPA-HQ-OAR-2002-0058-2468	Clark Diehl, Owner, Chips, Inc. / ArborTech Forest Products
EPA-HQ-OAR-2002-0058-2469	A. Robinson
EPA-HQ-OAR-2002-0058-2470	B. Thompson
EPA-HQ-OAR-2002-0058-2471	B. Hodgin
EPA-HQ-OAR-2002-0058-2472	B. Hilp
EPA-HQ-OAR-2002-0058-2473	B. and S. Gordon
EPA-HQ-OAR-2002-0058-2474	B. Collie
EPA-HQ-OAR-2002-0058-2475	C. Jurczewski
EPA-HQ-OAR-2002-0058-2476	C. Vanek
EPA-HQ-OAR-2002-0058-2477	C. Charonko
EPA-HQ-OAR-2002-0058-2478	C. Blake
EPA-HQ-OAR-2002-0058-2479	C. Rufflo
EPA-HQ-OAR-2002-0058-2480	A. and J. Brown
EPA-HQ-OAR-2002-0058-2481	C. Rufflo
EPA-HQ-OAR-2002-0058-2482	C. Metcalf
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EPA-HQ-OAR-2002-0058-2492	D. Alalem
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EPA-HQ-OAR-2002-0058-2495	E. Gottlieb
EPA-HQ-OAR-2002-0058-2496	E. Fuchs
EPA-HQ-OAR-2002-0058-2497	F. Infortunio
EPA-HQ-OAR-2002-0058-2498	G. Corl
EPA-HQ-OAR-2002-0058-2499	G. Bley
EPA-HQ-OAR-2002-0058-2500	G. True
EPA-HQ-OAR-2002-0058-2501	R. Devlin
EPA-HQ-OAR-2002-0058-2502	J. Castiano
EPA-HQ-OAR-2002-0058-2503	Dr. K. and P. Lohavanichbutr
EPA-HQ-OAR-2002-0058-2504	K. Kearney
EPA-HQ-OAR-2002-0058-2505	K. Keating-Secular
EPA-HQ-OAR-2002-0058-2506.1	Inc. (NGSB) Newport News, Virginia
EPA-HQ-OAR-2002-0058-2507	G. Preschle
EPA-HQ-OAR-2002-0058-2508	A. Larson
EPA-HQ-OAR-2002-0058-2509	H. Jones
EPA-HQ-OAR-2002-0058-2510	H. James
EPA-HQ-OAR-2002-0058-2511	I. Meyer
EPA-HQ-OAR-2002-0058-2512	I. Smith
EPA-HQ-OAR-2002-0058-2513	J. Roberts
EPA-HQ-OAR-2002-0058-2514	J. M. Rushforth
EPA-HQ-OAR-2002-0058-2515	J. Fasullo

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EPA-HQ-OAR-2002-0058-2516	J. Mcguire
EPA-HQ-OAR-2002-0058-2517	J. Doherty
EPA-HQ-OAR-2002-0058-2518	J. Parmalee
EPA-HQ-OAR-2002-0058-2519	A. Emerson
EPA-HQ-OAR-2002-0058-2520	J. Hinsdale
EPA-HQ-OAR-2002-0058-2521	A. Hellgren
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EPA-HQ-OAR-2002-0058-2523	B. Fukumoto
EPA-HQ-OAR-2002-0058-2524	B. Michot
EPA-HQ-OAR-2002-0058-2525.1	Myra C. Reece, Chief, Bureau of Air Quality, South Carolina Department of Health and Environmental Control (DHEC)
EPA-HQ-OAR-2002-0058-2526.1	Charles R. Faulds, Senior Vice President, Treating Division, Texas Electric Cooperatives, Inc. (TEC)
EPA-HQ-OAR-2002-0058-2527.1	Protection
EPA-HQ-OAR-2002-0058-2528	B. Braswell ,FDMS says "Anonymous"
EPA-HQ-OAR-2002-0058-2529.1	William R. Ermatinger, Sector Vice President, Human Resources and Administration, Northrop Grumman Shipbuilding, Inc
EPA-HQ-OAR-2002-0058-2530.1	Thomas A. Julia, President, Composite Panel Association (CPA)
EPA-HQ-OAR-2002-0058-2531	B. Hodgin
EPA-HQ-OAR-2002-0058-2532	B. Hilp
EPA-HQ-OAR-2002-0058-2533	Dr. B. and S. Gordon
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EPA-HQ-OAR-2002-0058-2543	A. Robinson
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EPA-HQ-OAR-2002-0058-2545	A. Grishaber
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EPA-HQ-OAR-2002-0058-2564	G. True
EPA-HQ-OAR-2002-0058-2565	G. Preschle
EPA-HQ-OAR-2002-0058-2566	H. Jones
EPA-HQ-OAR-2002-0058-2567	Dr. K. Marlin
EPA-HQ-OAR-2002-0058-2568	L. Stevens
EPA-HQ-OAR-2002-0058-2569	L. Magzis
EPA-HQ-OAR-2002-0058-2570	L. Haines
EPA-HQ-OAR-2002-0058-2571	L. Cook

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EPA-HQ-OAR-2002-0058-2572	L. Van Dame
EPA-HQ-OAR-2002-0058-2573	L. Butler
EPA-HQ-OAR-2002-0058-2574	L. Cole
EPA-HQ-OAR-2002-0058-2575	L. Driggers
EPA-HQ-OAR-2002-0058-2576	L. Sarhage
EPA-HQ-OAR-2002-0058-2577	Mrs. L. and J. Derck
EPA-HQ-OAR-2002-0058-2578	M. Holton
EPA-HQ-OAR-2002-0058-2579	M. Hubbert
EPA-HQ-OAR-2002-0058-2580	M. Loddengaard
EPA-HQ-OAR-2002-0058-2581	M. East
EPA-HQ-OAR-2002-0058-2582	Dr. M. Novak
EPA-HQ-OAR-2002-0058-2583	M. A. Vandervest
EPA-HQ-OAR-2002-0058-2584	M. Tryba
EPA-HQ-OAR-2002-0058-2585	M. Madrigal
EPA-HQ-OAR-2002-0058-2586	M. Joscelyn
EPA-HQ-OAR-2002-0058-2587	N. Aydt
EPA-HQ-OAR-2002-0058-2588	N. Brandt
EPA-HQ-OAR-2002-0058-2589	N. Goodspeed
EPA-HQ-OAR-2002-0058-2590	P. Dentremont
EPA-HQ-OAR-2002-0058-2591	P. Schexnayder
EPA-HQ-OAR-2002-0058-2592	P. M. Pizzo
EPA-HQ-OAR-2002-0058-2593	P. and M. Belov
EPA-HQ-OAR-2002-0058-2594	Dr. P. Wood
EPA-HQ-OAR-2002-0058-2595	R. Archdeacon
EPA-HQ-OAR-2002-0058-2596	R. Archdeacon
EPA-HQ-OAR-2002-0058-2597	R. Galloway
EPA-HQ-OAR-2002-0058-2598	Dr. R. Schwager
EPA-HQ-OAR-2002-0058-2599	Dennis A. Werblow, Director, Corporate Environmental Affairs, Decorative Panels International, Inc. (DPI)
EPA-HQ-OAR-2002-0058-2600.1	Scott Jones, CEO, Forest Landowners Association
EPA-HQ-OAR-2002-0058-2601	Governor Haley Barbour, Office of the Governor, State of Mississippi
EPA-HQ-OAR-2002-0058-2602.1	Lewis F. Gossett, President & Chief Executive Officer (CEO), South Carolina Manufacturers Alliance
EPA-HQ-OAR-2002-0058-2603.1	Candace Dinwiddie, Executive Director, Tennessee Forestry Association
EPA-HQ-OAR-2002-0058-2604	C. Metcalf
EPA-HQ-OAR-2002-0058-2605	C. Dawson
EPA-HQ-OAR-2002-0058-2606	D. Orellana
EPA-HQ-OAR-2002-0058-2607	D. Chapman
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EPA-HQ-OAR-2002-0058-2614	Dr. H. James
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EPA-HQ-OAR-2002-0058-2616	I. Smith
EPA-HQ-OAR-2002-0058-2617	J. Roberts
EPA-HQ-OAR-2002-0058-2618	J. M. Rushforth
EPA-HQ-OAR-2002-0058-2619	J. Fasullo
EPA-HQ-OAR-2002-0058-2620	Dr. J. Mcguire
EPA-HQ-OAR-2002-0058-2621	J. Doherty
EPA-HQ-OAR-2002-0058-2622	J. Parmalee
EPA-HQ-OAR-2002-0058-2623	J. Hinsdale
EPA-HQ-OAR-2002-0058-2624	J. V. Knapp
EPA-HQ-OAR-2002-0058-2625	K. Pomeroy
EPA-HQ-OAR-2002-0058-2626	J. Castiano
EPA-HQ-OAR-2002-0058-2627	K. & P. Lohavanichbutr

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EPA-HQ-OAR-2002-0058-2628	K. Kearney
EPA-HQ-OAR-2002-0058-2629	K. Hurley
EPA-HQ-OAR-2002-0058-2630.1	Jason A. Dagle, Safety & Environmental Manager, Wood-Mode, Incorporated
EPA-HQ-OAR-2002-0058-2631.1	Michael G. Dowd, Director, Air Division, Virginia Department of Environmental Quality (VADEQ)
EPA-HQ-OAR-2002-0058-2632.1	Russell A. Wozniak, EH&S Global Regulatory Affairs, The Dow Chemical Company (Dow)
EPA-HQ-OAR-2002-0058-2633.1	Lynell R. Yancey, Human Resources Manager, Flambeau River Papers LLC
EPA-HQ-OAR-2002-0058-2634.1	Specialty Chemicals, Inc.
EPA-HQ-OAR-2002-0058-2635.1	Mark Denzler, Vice President & COO, Illinois Manufacturers' Association (IMA)
EPA-HQ-OAR-2002-0058-2636	T. Loy
EPA-HQ-OAR-2002-0058-2637	J. Eisenhauer
EPA-HQ-OAR-2002-0058-2638	K. Hurley
EPA-HQ-OAR-2002-0058-2639	K. Pomeroy
EPA-HQ-OAR-2002-0058-2640	K. Gibson
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EPA-HQ-OAR-2002-0058-2643	L. Stevens
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EPA-HQ-OAR-2002-0058-2647	L. Van Dame
EPA-HQ-OAR-2002-0058-2648	J. Betz
EPA-HQ-OAR-2002-0058-2649	L. Butler
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EPA-HQ-OAR-2002-0058-2654	M. Holton
EPA-HQ-OAR-2002-0058-2655	M. Hubbert
EPA-HQ-OAR-2002-0058-2656	M. Loddengaard
EPA-HQ-OAR-2002-0058-2657	M. East
EPA-HQ-OAR-2002-0058-2658	M. East
EPA-HQ-OAR-2002-0058-2659	J. Harvey
EPA-HQ-OAR-2002-0058-2660	M. Novak
EPA-HQ-OAR-2002-0058-2661	M. A. Vandervest
EPA-HQ-OAR-2002-0058-2662	M. Tryba
EPA-HQ-OAR-2002-0058-2663	M. Madrigal
EPA-HQ-OAR-2002-0058-2664	M. Joscelyn
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EPA-HQ-OAR-2002-0058-2670	J. V. Knapp
EPA-HQ-OAR-2002-0058-2671	F. M. Pizzo
EPA-HQ-OAR-2002-0058-2672.1	Jeffrey T. Miller, President & Executive Director, Treated Wood Council (TWC)
EPA-HQ-OAR-2002-0058-2673.1	Tim Keneally, President, KapStone Kraft, on behalf of Kapstone Paper and Packaging Corporation (KapStone)
EPA-HQ-OAR-2002-0058-2674	Marsh Furniture Company
EPA-HQ-OAR-2002-0058-2675	Donald Christian, Flambeau River Papers, Park Falls, Wisconsin
EPA-HQ-OAR-2002-0058-2676.1	David Roosevelt, Chairman, Cabazon Band of Mission Indians
EPA-HQ-OAR-2002-0058-2677	P. and M. Belov
EPA-HQ-OAR-2002-0058-2678	P. Wood
EPA-HQ-OAR-2002-0058-2679.1	Kristine M. Krause, Vice President, Environmental, Wisconsin Electric Power Company dba We Energies
EPA-HQ-OAR-2002-0058-2680	R. Archdeacon
EPA-HQ-OAR-2002-0058-2681.1	Craig Harper, Environmental Manager, Collum’s Lumber Products, LLC
EPA-HQ-OAR-2002-0058-2682	R. Archdeacon
EPA-HQ-OAR-2002-0058-2683	R. Galloway

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EPA-HQ-OAR-2002-0058-2684	R. Schwager
EPA-HQ-OAR-2002-0058-2685	R. Haverlock
EPA-HQ-OAR-2002-0058-2686	R.Kosuth
EPA-HQ-OAR-2002-0058-2687	R. Liehman
EPA-HQ-OAR-2002-0058-2688	J. Mangan-Vanham
EPA-HQ-OAR-2002-0058-2689.1	Kristin Palecek, Environmental Manager, Flambeau River Papers
EPA-HQ-OAR-2002-0058-2690	Jay C. Moon, President & CEO, Mississippi Manufacturers Association (MMA)
EPA-HQ-OAR-2002-0058-2691.1	Tom Midyett, President, Tennessee Paper Council (TPC)
EPA-HQ-OAR-2002-0058-2692.1	Alliance (AHFA)
EPA-HQ-OAR-2002-0058-2693.1	Llewellyn Matthews, Northwest Pulp and Paper Association (NWPPA)
EPA-HQ-OAR-2002-0058-2694.1	Carroll L. Missimer, Global Director, Environmental Affairs, P. H. Glatfelter Company (Glatfelter)
EPA-HQ-OAR-2002-0058-2695.1	Michael D. Craig, Asst. V. P., Technical Manager, New Energy Corp. (NEC)
EPA-HQ-OAR-2002-0058-2696.1	Paul S. Dickens, Manager, Environmental Health and Safety, Canton Mill, Evergreen Packaging, Canton, North Carolina
EPA-HQ-OAR-2002-0058-2697.1	Governor Arnold Schwarzenegger, Office of the Governor, State of California
EPA-HQ-OAR-2002-0058-2698.1	W. Randall Rawson, President/Chief Executive Officer (CEO), American Boiler Manufacturers Association (ABMA)
EPA-HQ-OAR-2002-0058-2699.1	Richard T. Metcalf, Director, Environmental Affairs, Louisiana Mid-Continent Oil and Gas Association (LMOGA)
EPA-HQ-OAR-2002-0058-2701.1	Jeffrey O'Hearn, Corporate Environmental Engineer, Panolam Industries International Inc.
EPA-HQ-OAR-2002-0058-2702	Robert D. Bessette, President, Council Of Industrial Boiler Owners (CIBO)
EPA-HQ-OAR-2002-0058-2702.1	Robert D. Bessette, President, Council Of Industrial Boiler Owners (CIBO)
EPA-HQ-OAR-2002-0058-2702.2	Robert D. Bessette, President, Council Of Industrial Boiler Owners (CIBO)
EPA-HQ-OAR-2002-0058-2702.3	Robert D. Bessette, President, Council Of Industrial Boiler Owners (CIBO)
EPA-HQ-OAR-2002-0058-2702.4	Robert D. Bessette, President, Council Of Industrial Boiler Owners (CIBO)
EPA-HQ-OAR-2002-0058-2702.5	Robert D. Bessette, President, Council Of Industrial Boiler Owners (CIBO)
EPA-HQ-OAR-2002-0058-2703.1	John C. Hendricks, Manager, Air Quality Services, American Electric Power (AEP)
EPA-HQ-OAR-2002-0058-2704.1	Cindy Domenico, Chair, Boulder County Commissioners
EPA-HQ-OAR-2002-0058-2705.1	Bruce Coffee, Chief Engineer, Hurst Boiler and Welding Co., Inc.
EPA-HQ-OAR-2002-0058-2706.1	A. Preston Howard, Jr., P.E., President, Manufacturers and Chemical Industry Council of North Carolina (MCIC)
EPA-HQ-OAR-2002-0058-2707	Mass Comment Campaign sponsored by Members of United Steelworkers (USW) (421)
EPA-HQ-OAR-2002-0058-2707.1	Mass Comment Campaign attachment sponsored by Members of United Steelworkers (USW) (421)
EPA-HQ-OAR-2002-0058-2708.1	Al Hankins, Jr., President, Hankins Lumber Company, Inc.
EPA-HQ-OAR-2002-0058-2709	Tom Stinson, Environmental Manager, Sartell Mill, Verso Paper Corp.
EPA-HQ-OAR-2002-0058-2710	C. Lish
EPA-HQ-OAR-2002-0058-2711.1	Robert P. Strieter, Vice President, Environment Health and Safety, The Aluminum Association
EPA-HQ-OAR-2002-0058-2712.1	Paul Machtolf, VP and Resident Manager, Ponderay Newsprint Company
EPA-HQ-OAR-2002-0058-2713.1	California
EPA-HQ-OAR-2002-0058-2714.1	Theresa Pugh, Director, Environmental Services, American Public Power Association (APPA)
EPA-HQ-OAR-2002-0058-2715.2	Julie E. Goodman, Ph.D., DABT, Gradient
EPA-HQ-OAR-2002-0058-2716.1	Susan J. Miller, Vice President, Environment, Health, and Safety, Brick Industry Association (BIA)
EPA-HQ-OAR-2002-0058-2717.1	Mac Gibson, Alabama Timber Industries, Inc.
EPA-HQ-OAR-2002-0058-2718.1	Robert L. Garfield, Food Industry Environmental Council (FIEC)
EPA-HQ-OAR-2002-0058-2719.1	Forest and Paper Council (AFPC)
EPA-HQ-OAR-2002-0058-2720	Michael A. Livermore, Executive Director, Institute for Policy Integrity at New York University School of Law
EPA-HQ-OAR-2002-0058-2721.1	Greg A. Chandler, Director Technical, UPM-Blandin Paper
EPA-HQ-OAR-2002-0058-2722.1	Richard L. Killion, President and COO, Environmental Affairs, Babcock and Wilcox Power Generation Group
EPA-HQ-OAR-2002-0058-2723.1	Steven G. Hanson, Resident Manager, Graphic Packaging International (GPI) - Macon Mill
EPA-HQ-OAR-2002-0058-2724.1	Marketing & Business Development, American Public Gas Association (APGA)
EPA-HQ-OAR-2002-0058-2725.1	Anna Garcia, Executive Director, Ozone Transport Commission (OTC)
EPA-HQ-OAR-2002-0058-2726.1	Eril Bakken, Manager, Corporate Environmental Services and Land Management, Tucson Electric Power Company
EPA-HQ-OAR-2002-0058-2727.1	Christy Sammon, Director of Government and Regulatory Affairs, Southeastern Lumber Manufacturers Association (SLMA)
EPA-HQ-OAR-2002-0058-2729.1	Steven M. Maruszewski, Assistant Vice President, Office of Physical Plant Building, The Pennsylvania State University
EPA-HQ-OAR-2002-0058-2730.1	Lee Zeugin, Hunton & Williams LLP on behalf of Peabody Energy
EPA-HQ-OAR-2002-0058-2731.1	Henry T. Graham, Jr., Director, Environmental & Legal Affairs, Louisiana Chemical Association (LCA)
EPA-HQ-OAR-2002-0058-2732.1	Commerce
EPA-HQ-OAR-2002-0058-2733.1	Robert Klemans, Chair, Florida Electric Power Coordinating Group, Inc. (FCG)
EPA-HQ-OAR-2002-0058-2734.1	Robert R. Scott, Director, Air Resources Division, State of New Hampshire Department of Environmental Services
EPA-HQ-OAR-2002-0058-2735	C. Zukor

Document ID	Document Title
EPA-HQ-OAR-2002-0058-2736	Paul Mikesell, Director, Business Development and Operations, Building Block Chemicals, Cytec Industries Inc.
EPA-HQ-OAR-2002-0058-2736.1	Paul Mikesell, Director, Business Development and Operations, Building Block Chemicals, Cytec Industries Inc.
EPA-HQ-OAR-2002-0058-2737.1	Jon T. Howard, Lead Project Manager, Weston Solutions, Inc.
EPA-HQ-OAR-2002-0058-2739.1	Richard Lewis, President, Forest Resources Association (FRA)
EPA-HQ-OAR-2002-0058-2740.1	Corporation, et al.
EPA-HQ-OAR-2002-0058-2740.2	Corporation, et al.
EPA-HQ-OAR-2002-0058-2741.1	Chris M. Hobson, Chief Environmental Officer, Senior Vice President, Research and Environmental Affairs, Southern Company
EPA-HQ-OAR-2002-0058-2742.1	William A. (Billy) Thomas, President, Shuqualak Lumber Company, Inc.
EPA-HQ-OAR-2002-0058-2743.1	Environmental, Safety, Security, and Health, Ascend Performance Materials, LLC
EPA-HQ-OAR-2002-0058-2744.1	Kevin Korpi, Executive Director, Michigan Forest Products Council (MFPC)
EPA-HQ-OAR-2002-0058-2745.1	Traylor Champion, Vice President, Environmental Affairs, Georgia-Pacific LLC
EPA-HQ-OAR-2002-0058-2746.1	James P. Brooks, Director, Bureau of Air Quality, Maine Department of Environmental Protection (Maine DEP)
EPA-HQ-OAR-2002-0058-2747.1	Dirk J. Krouskop, Vice President, Safety, Health and Environment, MeadWestvaco Corporation (MWV)
EPA-HQ-OAR-2002-0058-2748.1	Kevin Korpi, Michigan Forest Products Council (MFPC)
EPA-HQ-OAR-2002-0058-2749.1	Jeffrey O'Hearn, Corporate Environmental Engineer, Panolam Industries International Inc.
EPA-HQ-OAR-2002-0058-2750.1	David P. Tenny, President and Chief Executive Officer (CEO), National Alliance of Forest Owners (NAFO)
EPA-HQ-OAR-2002-0058-2751.1	Rich Raiders, Environment and Sustainable Development Department, Arkema Inc.
EPA-HQ-OAR-2002-0058-2752.1	Paul Cicio, President, Industrial Energy Consumers of America (IECA)
EPA-HQ-OAR-2002-0058-2753	R. R. Perry
EPA-HQ-OAR-2002-0058-2754.1	Jeffrey R. Klieve, Director, Environmental Affairs, Monsanto Company (Monsanto)
EPA-HQ-OAR-2002-0058-2755.1	Quinlan J. Shea, III, Executive Director, Environment, Edison Electric Institute (EEI)
EPA-HQ-OAR-2002-0058-2756.1	Lisa Beal, Director, Environment and Construction Policy, Interstate Natural Gas Association of America (INGAA)
EPA-HQ-OAR-2002-0058-2757.1	Myra H. Glover, Director, Environmental Health and Safety, Entergy Services, Inc.
EPA-HQ-OAR-2002-0058-2758.1	Jeffery S. Hannapel, The Policy Group on Behalf of National Association for Surface Finishing (NASF)
EPA-HQ-OAR-2002-0058-2759.1	Sharene Shealey, Air Quality Specialist, RRI Energy
EPA-HQ-OAR-2002-0058-2760.1	James P. Brooks, Director, Bureau of Air Quality, State of Maine Department of Environmental Protection (Maine DEP)
EPA-HQ-OAR-2002-0058-2761.1	Walter Tyler, Director, Environmental Health and Safety, INVISTA S.à r.l.
EPA-HQ-OAR-2002-0058-2762.1	JoAnne Rau, Director of Environmental and Safety Management, The Dayton Power of Light Company (DP and L)
EPA-HQ-OAR-2002-0058-2763.1	Donald R. Schregardus, Deputy Assistant, DoD/Department of Navy
EPA-HQ-OAR-2002-0058-2764.1	Robert D. Morrison, Abbott Laboratories
EPA-HQ-OAR-2002-0058-2765.1	Mike Stroben, Duke Energy Business Services LLC, (Duke Energy), on behalf of Duke Energy Carolinas, LLC., et al.
EPA-HQ-OAR-2002-0058-2766.2	Jerry Call, Executive Vice President, American Foundry Society (AFS)
EPA-HQ-OAR-2002-0058-2767.1	Catharine Fitzsimons, Chief, Air Quality Bureau, Iowa Department of Natural Resources (IDNR)
EPA-HQ-OAR-2002-0058-2768	E. Trauner
EPA-HQ-OAR-2002-0058-2769.1	Leonard W. Sandridge, Executive Vice President and Chief Operating Officer, University of Virginia (UVA)
EPA-HQ-OAR-2002-0058-2770.1	Richard Lovely, General Manager, Grays Harbor Public Utility District (PUD)
EPA-HQ-OAR-2002-0058-2771.1	Audrae Erickson, President, Corn Refiners Association (CRA)
EPA-HQ-OAR-2002-0058-2772.1	Robert R. Perry, Advance Scientist, Environmental Department, FirstEnergy Generation Corporation (FGCO)
EPA-HQ-OAR-2002-0058-2772.2	Robert R. Perry, Advance Scientist, Environmental Department, FirstEnergy Generation Corporation (FGCO)
EPA-HQ-OAR-2002-0058-2773.1	(MPCA)
EPA-HQ-OAR-2002-0058-2774.1	W. Phillip Reese, Chairman, California Biomass Energy Alliance (CBEA)
EPA-HQ-OAR-2002-0058-2775.1	Britt Fleming, Van Ness Feldman, P.C. on behalf of BMW Group et al.
EPA-HQ-OAR-2002-0058-2775.2	Britt Fleming, Van Ness Feldman, P.C. on behalf of BMW Group et al.
EPA-HQ-OAR-2002-0058-2776.1	Gary Melow, Director, Michigan Biomass
EPA-HQ-OAR-2002-0058-2777.1	David M. Kiser, Vice President, Environment, Health, Safety, and Sustainability, International Paper Company
EPA-HQ-OAR-2002-0058-2777.2	David M. Kiser, Vice President, Environment, Health, Safety, and Sustainability, International Paper Company
EPA-HQ-OAR-2002-0058-2777.3	David M. Kiser, Vice President, Environment, Health, Safety, and Sustainability, International Paper Company
EPA-HQ-OAR-2002-0058-2777.4	David M. Kiser, Vice President, Environment, Health, Safety, and Sustainability, International Paper Company
EPA-HQ-OAR-2002-0058-2778.1	Robert E. McKenna, President and Chief Executive Officer (CEO), Motor & Equipment Manufacturers Association (MEMA)
EPA-HQ-OAR-2002-0058-2779.1	Dell Majure Kimberly-Clark Corporation (K-C)
EPA-HQ-OAR-2002-0058-2780.1	William A. Moore, General Counsel, Luminant
EPA-HQ-OAR-2002-0058-2781.1	Deb Hawkinson, Executive Director, Hardwood Federation (HF)
EPA-HQ-OAR-2002-0058-2782.1	Robin Mills Ridgway, Ph.D., P.E., Physical Facilities Director of Sustainability and Environmental Stewardship, Purdue University
EPA-HQ-OAR-2002-0058-2782.2	Robin Mills Ridgway, Ph.D., P.E., Physical Facilities Director of Sustainability and Environmental Stewardship, Purdue University
EPA-HQ-OAR-2002-0058-2783.1	Nina E. Butler, VP and Senior Environmental Counsel, Smurfit-Stone Container Corporation
EPA-HQ-OAR-2002-0058-2784.1	Victoria Jones, Vice President, Government Affair & Community Relations, The Clorox Company

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EPA-HQ-OAR-2002-0058-2785.1	Wayne Smith, Area Manager, Health, Safety & Environmental Manager, Westlake Chemical Corporation
EPA-HQ-OAR-2002-0058-2786.1	Company
EPA-HQ-OAR-2002-0058-2787.1	Benjamin L. Brandes, Director, Air Quality, National Mining Association (NMA)
EPA-HQ-OAR-2002-0058-2788.1	Michael J. Nasi, Counsel, Jackson Walker L.L.P. on behalf of Gulf Coast Lignite Coalition (GCLC)
EPA-HQ-OAR-2002-0058-2789.1	Trent Dougherty, Esq., Director of Legal Affairs, Ohio Environmental Council (OEC)
EPA-HQ-OAR-2002-0058-2790.1	John W. Fainter, Jr., President and Chief Executive Officer (CEO), Association of Electric Companies of Texas, Inc. (AECT)
EPA-HQ-OAR-2002-0058-2791.1	of Advocacy, U.S. Small Business Administration (SBA)
EPA-HQ-OAR-2002-0058-2792.1	Jim Griffin, Senior Director, American Chemistry Council (ACC)
EPA-HQ-OAR-2002-0058-2793.1	John C. deRuyter, Principal Consultant, DuPont Engineering Research and Technology
EPA-HQ-OAR-2002-0058-2793.2	John C. deRuyter, Principal Consultant, DuPont Engineering Research and Technology
EPA-HQ-OAR-2002-0058-2793.3	John C. deRuyter, Principal Consultant, DuPont Engineering Research and Technology
EPA-HQ-OAR-2002-0058-2794.1	Leslie Sue Ritts, National Environmental Development Association's Clean Air Project (NEDA/CAP)
EPA-HQ-OAR-2002-0058-2795.1	Jim Weeks, Executive Director, Michigan Municipal Electric Association (MMEA)
EPA-HQ-OAR-2002-0058-2796.1	David W. Hacker, Attorney, Environmental, Law Department, United States Steel Corporation (USS)
EPA-HQ-OAR-2002-0058-2797.1	Stephen E. Woock, EHS&S Federal Regulatory Affairs Manager, Weyerhaeuser Company
EPA-HQ-OAR-2002-0058-2797.2	Stephen E. Woock, EHS&S Federal Regulatory Affairs Manager, Weyerhaeuser Company
EPA-HQ-OAR-2002-0058-2797.3	Stephen E. Woock, EHS&S Federal Regulatory Affairs Manager, Weyerhaeuser Company
EPA-HQ-OAR-2002-0058-2797.4	Stephen E. Woock, EHS&S Federal Regulatory Affairs Manager, Weyerhaeuser Company
EPA-HQ-OAR-2002-0058-2798.1	Resources (NCDENR)
EPA-HQ-OAR-2002-0058-2799.1	William L. Kovacs, Senior Vice President, Environment, Technology and Regulatory Affairs, U.S. Chamber of Commerce
EPA-HQ-OAR-2002-0058-2800.1	Michael J. Nasi, Counsel, Jackson Walker L.L.P. on behalf of Gulf Coast Lignite Coalition (GCLC)
EPA-HQ-OAR-2002-0058-2801.1	David A. Buff, Principal Engineer, Golder Associates Inc. on behalf of the Florida Sugar Industry (FSI)
EPA-HQ-OAR-2002-0058-2802.1	Debra J. Jezouit and Megan Berge, Baker Botts L.L.P. on behalf of Class of '85 Regulatory Response Group
EPA-HQ-OAR-2002-0058-2803.1	Michael J. Hutcheson, Ameren Corporation
EPA-HQ-OAR-2002-0058-2804.1	Ashok K. Jain, Southern Regional Manager, National Council for Air and Stream Improvement (NCASI)
EPA-HQ-OAR-2002-0058-2805.1	Rachel Smolker, Biofuelwatch, et al.
EPA-HQ-OAR-2002-0058-2806.1	Kevin P. Bundy, Senior Attorney, Center for Biological Diversity
EPA-HQ-OAR-2002-0058-2807.1	Paul F. Perlwitz, Environmental Manager, Nippon Paper Industries USA Co., Ltd (NPIUSA)
EPA-HQ-OAR-2002-0058-2808.1	Douglas A. McWilliams, Counsel, Squire, Sanders and Dempsey L.L. P. on behalf of American Municipal Power, Inc. (AMP)
EPA-HQ-OAR-2002-0058-2809.1	Glenn C. England, Principal, Environ International Corporation
EPA-HQ-OAR-2002-0058-2810.1	Nilaksh Kothari, P.E., General Manager, Manitowoc Public Utilities
EPA-HQ-OAR-2002-0058-2810.2	Nilaksh Kothari, P.E., General Manager, Manitowoc Public Utilities
EPA-HQ-OAR-2002-0058-2811.1	Douglas A. McWilliams, Counsel on behalf of ArcelorMittal USA Inc.
EPA-HQ-OAR-2002-0058-2812.1	Timothy J. Porter, Director, Air Quality Management, Wheelabrator Technologies Inc. (WTI)
EPA-HQ-OAR-2002-0058-2813	document, please see EPA-HQ-OAR-2002-0058-2804.0 and OAR-2002-0058-2804.1
EPA-HQ-OAR-2002-0058-2814.1	Ruth Cook, President and Bruce C. Alt, CAE, Executive Vice President, Mississippi Forestry Association (MFA)
EPA-HQ-OAR-2002-0058-2815.1	Kellie Daniels, Chair on behalf of the Board of the Grays Harbor Chamber of Commerce
EPA-HQ-OAR-2002-0058-2816.1	Robert Ellerhorst, Director of Utilities, Power and Water Department, Michigan State University (MSU)
EPA-HQ-OAR-2002-0058-2816.2	Robert Ellerhorst, Director of Utilities, Power and Water Department, Michigan State University (MSU)
EPA-HQ-OAR-2002-0058-2816.3	Robert Ellerhorst, Director of Utilities, Power and Water Department, Michigan State University (MSU)
EPA-HQ-OAR-2002-0058-2816.4	Robert Ellerhorst, Director of Utilities, Power and Water Department, Michigan State University (MSU)
EPA-HQ-OAR-2002-0058-2817.1	Steve Zika, Chief Executive Officer, Hampton Lumber Mills, Inc.
EPA-HQ-OAR-2002-0058-2818.1	Chris Korleski, Director, Ohio Environmental Protection Agency (Ohio EPA)
EPA-HQ-OAR-2002-0058-2819.1	Jeff A. McNelly, Executive Director, ARIPPA
EPA-HQ-OAR-2002-0058-2820.1	Shelley Schneider, Air Quality Division Administrator, Nebraska Department of Environmental Quality (NDEQ)
EPA-HQ-OAR-2002-0058-2821.1	John J. Petchul, P.E., Staff Environmental Engineer, Greif Packaging LLC
EPA-HQ-OAR-2002-0058-2822.1	Cynthia L. Karlic, Regional Environmental Director, NRG Energy, Inc.
EPA-HQ-OAR-2002-0058-2823.1	Guy R. Martin, Director, Environment, Sustainability Group, Domtar Corporation
EPA-HQ-OAR-2002-0058-2824.1	Melvin E. Keener, Ph.D., Executive Director, Coalition for Responsible Waste Incineration (CRWI)
EPA-HQ-OAR-2002-0058-2825.1	Russell Strader, Environmental Manager, Boise Cascade, L.L.C.
EPA-HQ-OAR-2002-0058-2826.1	James K. Pattillo, President, Coastal Plywood Company
EPA-HQ-OAR-2002-0058-2827.1	James Johnson, President, U.S. Beet Sugar Association (USBSA)
EPA-HQ-OAR-2002-0058-2828.1	Rusty Camp, EH&S Manager, Wellborn Cabinet, Inc.
EPA-HQ-OAR-2002-0058-2829.1	Tim Hagley, Supervisor, Air Quality, Minnesota Power (ALLETE)
EPA-HQ-OAR-2002-0058-2830.1	John C. deRuyter, DuPont Pigments (Also see EPA-HQ-OAR-2002-0058-2793.3)
EPA-HQ-OAR-2002-0058-2831.1	Ted Michaels, President, Energy Recovery Council (ERC)
EPA-HQ-OAR-2002-0058-2832.1	Arthur Blazer, New Mexico State Forester and Chair, Council of Western State Foresters (CWSF)

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EPA-HQ-OAR-2002-0058-2833.1	Dean C. DeLorey, Director, Environmental Affairs, The Amalgamated Sugar Company LLC (TASCO)
EPA-HQ-OAR-2002-0058-2834.1	Ken Wiegand, Chief Engineer, Denison University
EPA-HQ-OAR-2002-0058-2835.1	Bill Wemhoff, Senior Principal, Environmental Policy, National Rural Electric Cooperative Association (NRECA)
EPA-HQ-OAR-2002-0058-2836	Junior Frazier, Plant Supervisor, Particleboard Division, Webb Furniture Enterprises, Inc.
EPA-HQ-OAR-2002-0058-2837.1	G. Vinson Hellwig, Chief, Air Quality Division, Michigan Department of Natural Resources and Environment (DNRE)
EPA-HQ-OAR-2002-0058-2838.1	Brian Chaples, Vice President of Operations, Door Facings, Masonite Corporation
EPA-HQ-OAR-2002-0058-2839	Han-Juergen Obermaier, Operations Director, Kronospan LLC
EPA-HQ-OAR-2002-0058-2840.1	Edward E. Quick, Ph.D., Global EHS Director, Celanese International Corporation
EPA-HQ-OAR-2002-0058-2841.1	Vinson Hellwig and Robert Colby, Co-Chairs, NACAA Air Toxics Committee, National Association of Clean Air Agencies (NACAA)
EPA-HQ-OAR-2002-0058-2842.1	Kevin P. Bundy, Senior Attorney, Center for Biological Diversity et al.
EPA-HQ-OAR-2002-0058-2843.1	Frederick R. Albrecht, Vice President, Manufacturing, SCA Tissue
EPA-HQ-OAR-2002-0058-2845.1	Alicia Oman, Director, Energy & Resources Policy, National Association of Manufacturers (NAM)
EPA-HQ-OAR-2002-0058-2846.1	Lynn D. Westfall, Senior Vice President, External Affairs and Chief Economist, Tesoro Companies, Inc.
EPA-HQ-OAR-2002-0058-2847	Wayne K. Scharber, Vice President for Environmental Affairs, Tennessee Chamber of Commerce & Industry
EPA-HQ-OAR-2002-0058-2848.1	Barry Christensen, Manager Air Quality, Occidental Chemical Corporation (OCC)
EPA-HQ-OAR-2002-0058-2849.1	Bruce A. Steiner, President, American Coke and Coal Chemicals Institute (ACCCI)
EPA-HQ-OAR-2002-0058-2850.1	Joseph S. Hensel, Director of Field Services, Rochester Public Utilities (RPU)
EPA-HQ-OAR-2002-0058-2851.1	Susan Swanson, Executive Director, Allegheny Hardwood Utilization Group, Inc. (AHUG)
EPA-HQ-OAR-2002-0058-2852.1	Representative Jeannie Darnielle, 27th Legislative District, State of Washington House of Representatives
EPA-HQ-OAR-2002-0058-2853.1	Brad James, Manager of Consulting, Trinity Consultants on behalf of United States Sugar Corporation (U.S. Sugar)
EPA-HQ-OAR-2002-0058-2854.1	Commerce
EPA-HQ-OAR-2002-0058-2855.1	James C. Jackson, P.E., Director of Environment, Boise Inc.
EPA-HQ-OAR-2002-0058-2856.1	Mick Baranko, Environmental Compliance Officer, Douglas County Forest Products
EPA-HQ-OAR-2002-0058-2857.1	Debbie Hastings, Vice-President for Environmental Affairs, Texas Oil & Gas Association (TxOGA)
EPA-HQ-OAR-2002-0058-2858.1	Dave Leding, Plant Manager, Flakeboard America
EPA-HQ-OAR-2002-0058-2859.1	Compliance, Dynegy Midwest Operations, Dynegy, Inc
EPA-HQ-OAR-2002-0058-2860.1	Steven W. Koehn, President, Maryland State Forester, National Association of State Foresters (NASF)
EPA-HQ-OAR-2002-0058-2861.1	Corporation, America
EPA-HQ-OAR-2002-0058-2862	Marvin A. Lewallen, Director, Environmental & Safety, Clearwater Paper Corporation
EPA-HQ-OAR-2002-0058-2863.1	Christopher S. Colman, Deputy General Counsel, on behalf of HOVENSA, LLC
EPA-HQ-OAR-2002-0058-2863.2	Christopher S. Colman, Deputy General Counsel, on behalf of HOVENSA, LLC
EPA-HQ-OAR-2002-0058-2863.3	Christopher S. Colman, Deputy General Counsel, on behalf of HOVENSA, LLC
EPA-HQ-OAR-2002-0058-2864.1	Regina Hopper, President and CEO, America's Natural Gas Alliance (ANGA)
EPA-HQ-OAR-2002-0058-2865.1	Thomas D. Evans, Chief Operating Officer, Coastal Forest Resource Company
EPA-HQ-OAR-2002-0058-2866.1	Dale A. Riddle, Vice President, Legal Affairs, Seneca Sustainable Energy
EPA-HQ-OAR-2002-0058-2867.1	Dan F. Hunter, Manager, Regulatory Issues, ConocoPhillips
EPA-HQ-OAR-2002-0058-2868.1	Caroline Choi, Executive Director, Environmental Services and Strategy, Progress Energy
EPA-HQ-OAR-2002-0058-2869.1	Peter Zalzal, Environmental Defense Fund (EDF)
EPA-HQ-OAR-2002-0058-2870.1	David A. Bischel, President, California Foresry Association
EPA-HQ-OAR-2002-0058-2871.1	Eveleen Muehlethaler, Vice President- Environmental Affairs, Port Townsend Paper Corporation (PTPC)
EPA-HQ-OAR-2002-0058-2872.1	Tracy Smith, Vice President, Operations, Coastal Forest Products
EPA-HQ-OAR-2002-0058-2873.1	Carole J. Stapper, Environmental Manager, Air, Temple-Inland
EPA-HQ-OAR-2002-0058-2874.1	William C. Herz, Vice President, Scientific Programs, The Fretilizer Institute (TFI)
EPA-HQ-OAR-2002-0058-2875.1	Ann W. McIver, QEP, Citizens Thermal
EPA-HQ-OAR-2002-0058-2876.1	Laura Colban, Chief Executive Officer (CEO), Skanden Energy
EPA-HQ-OAR-2002-0058-2877.1	David C. Ailor, P.E., Vice President, Regulatory Affairs, National Oilseed Processors Association (NOPA)
EPA-HQ-OAR-2002-0058-2878.1	Ohio Coal Association
EPA-HQ-OAR-2002-0058-2879.1	of Advocacy, U.S. Small Business Administration (SBA)
EPA-HQ-OAR-2002-0058-2880.1	Lee B. Zeugin and Lauren E. Freeman, Hunton & Williams LLP on behalf of Utility Air Regulatory Group (UARG)
EPA-HQ-OAR-2002-0058-2881.1	David Z. Skolasinski, District Manager, Environmental, Regulatory Planning & Analysis, Cliffs Natural Resources Inc.
EPA-HQ-OAR-2002-0058-2882.1	Wayne J. Galler, Air Workgroup Chair and Deborah A. Phillips, Executive Director, Georgia Industry Environmental Coalition (GIEC)
EPA-HQ-OAR-2002-0058-2883.1	Gary W. Kruger, Director, Environment and Sustainable Development, Morton Salt
EPA-HQ-OAR-2002-0058-2884.1	Michael Robertson, Minnesota Chamber of Commerce
EPA-HQ-OAR-2002-0058-2885.1	Aubra Anthony Jr., President and CEO, Anthony Forest Products Company (AFP)
EPA-HQ-OAR-2002-0058-2886.1	Association (ACA)
EPA-HQ-OAR-2002-0058-2887.1	Marshall D. Moore, Director, Technology and Advocacy, Chemtura Corporation

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EPA-HQ-OAR-2002-0058-2887.2	Marshall D. Moore, Director, Technology and Advocacy, Chemtura Corporation
EPA-HQ-OAR-2002-0058-2887.3	Marshall D. Moore, Director, Technology and Advocacy, Chemtura Corporation
EPA-HQ-OAR-2002-0058-2887.4	Marshall D. Moore, Director, Technology and Advocacy, Chemtura Corporation
EPA-HQ-OAR-2002-0058-2888.1	Jeffery S. Hannapel, The Policy Group, National Association for Surface Finishing (NASF)
EPA-HQ-OAR-2002-0058-2889.1	Stephen J. Faehner, Vice President, American Wood Fibers (AWF)
EPA-HQ-OAR-2002-0058-2890.1	S. Lewis Ebert, President and Chief Executive Officer (CEO), North Carolina Chamber
EPA-HQ-OAR-2002-0058-2891.1	Margaret Wilson Sembos, Kestrel Horizons, LLC on behalf of Curtis Schopp, National Salvage & Service Corporation (NSSC)
EPA-HQ-OAR-2002-0058-2892.1	Catherine W. McCutchen, Environmental Engineer, Blue Heron Paper Company
EPA-HQ-OAR-2002-0058-2893.1	Arthur N. Marin, Executive Director, Northeast States for Coordinated Air Use Management (NESCAUM)
EPA-HQ-OAR-2002-0058-2894.1	Bethany J. Johnson, Environment Health and Safety (EHS) Policy Analysis, The Boeing Company
EPA-HQ-OAR-2002-0058-2895.1	Paul Kramer, President, Koda Energy
EPA-HQ-OAR-2002-0058-2896.1	Anna K. Chittum, Research Associate, Industry Program, American Council for an Energy-Efficient Economy (ACEEE)
EPA-HQ-OAR-2002-0058-2897.1	Energy Company
EPA-HQ-OAR-2002-0058-2898.1	Joe Muehlbach, Director, Facilities and Environmental Policy, Quad/Graphics, Inc.
EPA-HQ-OAR-2002-0058-2899.1	A. Steven Young, President, Association of Independent Corrugated Converters (AICC)
EPA-HQ-OAR-2002-0058-2900.1	Frankie Baugh, Scotch Plywood Company
EPA-HQ-OAR-2002-0058-2901.1	Jennifer Klein, Director, Energy and Environmental Policy, Ohio Chamber of Commerce
EPA-HQ-OAR-2002-0058-2902.1	Paul J. Bredwell III, U.S. Poultry and Egg Association et al.
EPA-HQ-OAR-2002-0058-2903.1	Frank A. Stanonik, Chief Technical Advisor, Air-Conditioning, Heating, and Refrigeration Institute (AHRI)
EPA-HQ-OAR-2002-0058-2904.1	Kathryn M. Cunningham, Senior Environmental Planner, Environmental Services, Consumers Energy Company
EPA-HQ-OAR-2002-0058-2905	Randall D. Quintrell, Counsel for Georgia Paper & Forest Products Association (GPFPA)
EPA-HQ-OAR-2002-0058-2906.1	Paul Lyskava, Executive Director, Pennsylvania Forest Products Association
EPA-HQ-OAR-2002-0058-2907.1	David G. Koster, Operations Director, Holland Board of Public Works (HBPW), Michigan
EPA-HQ-OAR-2002-0058-2908.1	Pamela F. Faggert, Vice President and Chief Environmental Officer, Dominion Resources Services, Inc.
EPA-HQ-OAR-2002-0058-2909.1	William W. (Bill) Grygar II, Director, EHS & Regulatory, Anadarko Petroleum Corporation
EPA-HQ-OAR-2002-0058-2910.1	Michele Pugh, Director, Environmental Affairs, Flint Hills Resources, LP (FHR)
EPA-HQ-OAR-2002-0058-2911.1	Shawn Keough, Executive Director, Associated Logging Contractors, Inc. of Idaho
EPA-HQ-OAR-2002-0058-2912	Gordon M. Smith, Mitsubishi Polyester Film, Inc.
EPA-HQ-OAR-2002-0058-2913.1	Mark W. Kowlzan, Chief Executive Officer, Packaging Corporation of America (PCA)
EPA-HQ-OAR-2002-0058-2914.1	Gary Chandler, Vice President, Government Affairs, Association of Washington Business (AWB)
EPA-HQ-OAR-2002-0058-2915.1	Richard T. Weber, Director, Government & Environmental Affairs, Flakeboard America
EPA-HQ-OAR-2002-0058-2916	of Advocacy, U.S. Small Business Administration (SBA) (corrected version of EPA-HQ-OAR-2002-0058-2791)
EPA-HQ-OAR-2002-0058-2917.1	Roy W. Wood, Health Safety and Environment, Eastman Kodak Company
EPA-HQ-OAR-2002-0058-2918.1	Robert Thornton, President, International District Energy Association (IDEA)
EPA-HQ-OAR-2002-0058-2919.1	Particleboard
EPA-HQ-OAR-2002-0058-2920.1	David Bonistall, Vice President Environmental, Health and Safety, NewPage Corporation
EPA-HQ-OAR-2002-0058-2921.1	Floyd DesChamps, Vice President, Policy and Research, Alliance to Save Energy
EPA-HQ-OAR-2002-0058-2922	Michele R. Dunn, Capitol Affairs on behalf of Repreve Renewables, LLC
EPA-HQ-OAR-2002-0058-2923.1	Michael C. Stiefermann, P.E., Environmental & Operations Engineer, Central Electric Power Cooperative (CEPC)
EPA-HQ-OAR-2002-0058-2924.1	Todd A. Tolbert, Environmental Analyst II, Associated Electric Cooperative, Inc. (AECI)
EPA-HQ-OAR-2002-0058-2925.1	John Ledger, Vice President, Associated Oregon Industries (AOI)
EPA-HQ-OAR-2002-0058-2926.1	Senior Manager, Government Relations, Society of Chemical Manufacturers and Affiliates (SOCMA)
EPA-HQ-OAR-2002-0058-2927.1	Mark Calmes, Vice President, Environmental, Office of Compliance and Ethics, Archer Daniels Midland Company (ADM)
EPA-HQ-OAR-2002-0058-2928.1	Chris Jarmer, Water Policy and Forest Regulation Director, Oregon Forest Industries Council (OFIC)
EPA-HQ-OAR-2002-0058-2929.1	Jason Dagle, Safety & Environmental Manager, Wood-Mode, Inc.
EPA-HQ-OAR-2002-0058-2930.1	Darell Soyars, Manager, Environmental Compliance, Avista Corporation
EPA-HQ-OAR-2002-0058-2931.1	Tim W. Sonnichsen, Sonnichsen Engineering, LLC
EPA-HQ-OAR-2002-0058-2932.1	Lisa Jacobson, President, Business Council for Sustainable Energy (BCSE)
EPA-HQ-OAR-2002-0058-2933.1	Scott Manley, Environmental Policy Director, Wisconsin Manufacturers & Commerce (WMC)
EPA-HQ-OAR-2002-0058-2934.1	Robert E. Cleaves, President & Chief Executive Officer, Biomass Power Association (BPA)
EPA-HQ-OAR-2002-0058-2935.1	Matthew Todd, American Petroleum Institute (API) and David Friedman, National Petrochemical and Refiners Association (NPRA)
EPA-HQ-OAR-2002-0058-2936.1	Curtis Schopp, National Salvage & Services Corporation (NSSC)
EPA-HQ-OAR-2002-0058-2937.1	David Foerter, Executive Director, Institute of Clean Air Companies (ICAC)
EPA-HQ-OAR-2002-0058-2938.1	Jerry Osheka, Director, EHS, Chemicals, PPG Industries, Inc.
EPA-HQ-OAR-2002-0058-2939.1	Dave Lyon, Manager on behalf of Sean Coffey, Plant Manager, Flakeboard
EPA-HQ-OAR-2002-0058-2940.1	Martha E. Rudolph, Executive Director, Colorado Department of Public Health and Environment

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EPA-HQ-OAR-2002-0058-2941.1	Sarah E. Amick, Environmental Counsel, Rubber Manufacturers Association (RMA)
EPA-HQ-OAR-2002-0058-2942.1	Synthetic Fuels Association (LCSFA)
EPA-HQ-OAR-2002-0058-2943.1	Chris Welch, Environmental Specialist, Colorado Springs Utilities (CSU)
EPA-HQ-OAR-2002-0058-2944.1	Richard Krock, Technical Director, The Vinyl Institute (VI)
EPA-HQ-OAR-2002-0058-2945.1	al.
EPA-HQ-OAR-2002-0058-2946.1	Brad Cooley, Director, Environmental Engineering, GDF SUEZ Energy Generation NA, Inc. (GSEGNA)
EPA-HQ-OAR-2002-0058-2947.1	Melissa Mullarkey, Recycled Energy Development, LLC (RED)
EPA-HQ-OAR-2002-0058-2948	John W. Myers, Director, Environmental Policy, Clean and Renewable Energy, Tennessee Valley Authority (TVA)
EPA-HQ-OAR-2002-0058-2949	Bill Buchan, Chief Executive Officer (CEO), Market Potential, Inc. on behalf of Graphic Packaging International, Inc.
EPA-HQ-OAR-2002-0058-2950	Thomas M. Bakk, State Senator, District 6, State of Minnesota Senate et al.
EPA-HQ-OAR-2002-0058-2951	Rachel Smolker, Biofuel Watch et al.
EPA-HQ-OAR-2002-0058-2952.1	Kenneth R. Gallant, Manager, Environmental Services, Verso Paper Corps. Androscoggin Mill
EPA-HQ-OAR-2002-0058-2953.1	John T. Heard, Legislative Counsel, Virginia Coal Association, Inc. (VCA)
EPA-HQ-OAR-2002-0058-2954.1	John M. Irving, Manager of Power Supply, The Burlington Electric Department, McNeil Generating Station
EPA-HQ-OAR-2002-0058-2955.1	Richard Rosvold, Manager, Air Quality, Environmental Services Department, Xcel Energy Services Inc.
EPA-HQ-OAR-2002-0058-2956.1	James Santory, Director, Environmental, Health and Safety, Calgon Carbon Corporation
EPA-HQ-OAR-2002-0058-2957.1	(WVMA)
EPA-HQ-OAR-2002-0058-2958.1	Senator Christopher S. Bond, Missouri United States Senate
EPA-HQ-OAR-2002-0058-2959	Representative Kevin Van De Wege, 24th Legislative District, State of Washington House of Representatives et al.
EPA-HQ-OAR-2002-0058-2960.1	Matthew Todd, American Petroleum Institute (API) and David Friedman, National Petrochemical and Refiners Association (NPRA)
EPA-HQ-OAR-2002-0058-2960.2	Matthew Todd, American Petroleum Institute (API) and David Friedman, National Petrochemical and Refiners Association (NPRA)
EPA-HQ-OAR-2002-0058-2961.1	Tom Piccorelli, Assistant Vice President, Operations, Environmental Health and Safety Office, Oberlin College
EPA-HQ-OAR-2002-0058-2962.1	Kyle D. Gibbs, General Manager, Marshall Missouri Municipal Utilities (MMU)
EPA-HQ-OAR-2002-0058-2963.1	John W. Meyers, Director, Environmental Policy, Clean and Renewable Energy, Tennessee Valley Authority (TVA)
EPA-HQ-OAR-2002-0058-2964.1	Manufacturing, Energy, Allied Industrial, and Service Workers International Union (USW)
EPA-HQ-OAR-2002-0058-2965.1	David B. Struhs, Vice President, Sustainability Strategy, C3
EPA-HQ-OAR-2002-0058-2966.1	William Rogers, Senior Technological Specialist, Environmental Strategies, DTE Energy (DTE)
EPA-HQ-OAR-2002-0058-2967.1	Michael A. Palazzolo, Manager Air Services, EHS Services North America, Alcoa Inc.
EPA-HQ-OAR-2002-0058-2968.1	Douglas J. Van Pelt, Environmental Advisor, Downstream and Chemical SH&E, ExxonMobil Refining and Supply Company
EPA-HQ-OAR-2002-0058-2968.2	Douglas J. Van Pelt, Environmental Advisor, Downstream and Chemical SH&E, ExxonMobil Refining and Supply Company
EPA-HQ-OAR-2002-0058-2968.3	Douglas J. Van Pelt, Environmental Advisor, Downstream and Chemical SH&E, ExxonMobil Refining and Supply Company
EPA-HQ-OAR-2002-0058-2969.1	William O'Sullivan, P.E., Director, New Jersey Department of Environmental Protection (NJDEP)
EPA-HQ-OAR-2002-0058-2970.1	Michigan Sugar Company
EPA-HQ-OAR-2002-0058-2971	D. Skarada
EPA-HQ-OAR-2002-0058-2972	D. Armstrong
EPA-HQ-OAR-2002-0058-2973	D. Armstrong
EPA-HQ-OAR-2002-0058-2974	G. Girard
EPA-HQ-OAR-2002-0058-2975	A. Avanti
EPA-HQ-OAR-2002-0058-2976	C. Alexandre
EPA-HQ-OAR-2002-0058-2977	L. Layne
EPA-HQ-OAR-2002-0058-2978	K. Barber
EPA-HQ-OAR-2002-0058-2979	S. Rudnicki
EPA-HQ-OAR-2002-0058-2980	R. Skaar
EPA-HQ-OAR-2002-0058-2981	D. Jones
EPA-HQ-OAR-2002-0058-2982	F. Strege
EPA-HQ-OAR-2002-0058-2983	M. Pool
EPA-HQ-OAR-2002-0058-2984	E. Amba and D. Caldwell
EPA-HQ-OAR-2002-0058-2985	M. Picardi
EPA-HQ-OAR-2002-0058-2986.1	Jeff Applekamp, Director, Government Affairs, Gas Processors Association (GPA)
EPA-HQ-OAR-2002-0058-2987.1	Ted Sturdevant, Director, Department of Ecologym, State of Washington
EPA-HQ-OAR-2002-0058-2988	W. Otu'Upu
EPA-HQ-OAR-2002-0058-2989	M. Gates
EPA-HQ-OAR-2002-0058-2990	W. Krakauer
EPA-HQ-OAR-2002-0058-2991	M. Cleary
EPA-HQ-OAR-2002-0058-2992	N. Bartol
EPA-HQ-OAR-2002-0058-2993	P. Amazalorso

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EPA-HQ-OAR-2002-0058-2994	P. Moran
EPA-HQ-OAR-2002-0058-2995.1	Terry Walmsley, Vice President of Environmental and Public Affairs, Fibrowatt LLC
EPA-HQ-OAR-2002-0058-2996	Richard Caserta, President, Red Hill Grinding Wheel Corporation
EPA-HQ-OAR-2002-0058-2997.1	Michael L. Corvese, Director of Global Marketing,Thermo Fisher Scientific Inc.
EPA-HQ-OAR-2002-0058-2998.1	Kevin M. Dempsey, Vice President, Public Policy and General Counsel, American Iron and Steel Institute (AISI)
EPA-HQ-OAR-2002-0058-2999.1	Dennis C. McComb, Environmental and Safety Manager, Lincoln Paper and Tissue, LLC (LPT)
EPA-HQ-OAR-2002-0058-3000	C. Schoen
EPA-HQ-OAR-2002-0058-3001	C. Mies
EPA-HQ-OAR-2002-0058-3002	C. Jacobs
EPA-HQ-OAR-2002-0058-3003	C. Farnsworth
EPA-HQ-OAR-2002-0058-3004	C. Farnsworth
EPA-HQ-OAR-2002-0058-3005	D. Pedersen
EPA-HQ-OAR-2002-0058-3006	T. and K. Stempel
EPA-HQ-OAR-2002-0058-3007	M. Decker
EPA-HQ-OAR-2002-0058-3008	T. Au
EPA-HQ-OAR-2002-0058-3009	T. MacKrell
EPA-HQ-OAR-2002-0058-3010	T. Derf
EPA-HQ-OAR-2002-0058-3011	T. Londino
EPA-HQ-OAR-2002-0058-3012	V. Dickey
EPA-HQ-OAR-2002-0058-3013	V. Vernon
EPA-HQ-OAR-2002-0058-3014	V. Walsh
EPA-HQ-OAR-2002-0058-3015	V. and M. Miller
EPA-HQ-OAR-2002-0058-3016	W. Branson
EPA-HQ-OAR-2002-0058-3017	J. Davis
EPA-HQ-OAR-2002-0058-3018	A. Harlib
EPA-HQ-OAR-2002-0058-3019	J. Schweig
EPA-HQ-OAR-2002-0058-3020	J. Deming
EPA-HQ-OAR-2002-0058-3021	J. Staton
EPA-HQ-OAR-2002-0058-3022	J. Wright
EPA-HQ-OAR-2002-0058-3023	J. Jacobs
EPA-HQ-OAR-2002-0058-3024	J. Sullivan
EPA-HQ-OAR-2002-0058-3025	J. & J. Turney
EPA-HQ-OAR-2002-0058-3026	J. Kneidl
EPA-HQ-OAR-2002-0058-3027	J. Smith
EPA-HQ-OAR-2002-0058-3028	K. Jain
EPA-HQ-OAR-2002-0058-3029	A. Bastian
EPA-HQ-OAR-2002-0058-3030	K. Trochlell
EPA-HQ-OAR-2002-0058-3031	K. Schiller
EPA-HQ-OAR-2002-0058-3032	K. Brignell
EPA-HQ-OAR-2002-0058-3033	K. Peterson
EPA-HQ-OAR-2002-0058-3034	L. Freese
EPA-HQ-OAR-2002-0058-3035	L. Jobe
EPA-HQ-OAR-2002-0058-3036	P. Grover
EPA-HQ-OAR-2002-0058-3037	P. Oaks
EPA-HQ-OAR-2002-0058-3038	P. and J. Meshulam
EPA-HQ-OAR-2002-0058-3039	R. Dunterman
EPA-HQ-OAR-2002-0058-3040	R. Kosuth
EPA-HQ-OAR-2002-0058-3041	R. Liebman
EPA-HQ-OAR-2002-0058-3042	R. Rinker
EPA-HQ-OAR-2002-0058-3043	R. Devlin
EPA-HQ-OAR-2002-0058-3044	S. Parsons
EPA-HQ-OAR-2002-0058-3045	S. Noll
EPA-HQ-OAR-2002-0058-3046	M. McGuire
EPA-HQ-OAR-2002-0058-3047	S. Bahr
EPA-HQ-OAR-2002-0058-3048	S. Ransom
EPA-HQ-OAR-2002-0058-3049	S. Deflon

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EPA-HQ-OAR-2002-0058-3050	S. Deutsch
EPA-HQ-OAR-2002-0058-3051	S. Calderon
EPA-HQ-OAR-2002-0058-3052	S. Golden
EPA-HQ-OAR-2002-0058-3053	A. Michel
EPA-HQ-OAR-2002-0058-3054	S. Linn
EPA-HQ-OAR-2002-0058-3055	S. Stowell-Hardcastle
EPA-HQ-OAR-2002-0058-3056	S. Skal
EPA-HQ-OAR-2002-0058-3057	M. Beczkiewicz
EPA-HQ-OAR-2002-0058-3058	S. Smith
EPA-HQ-OAR-2002-0058-3059	S. Payer
EPA-HQ-OAR-2002-0058-3060	S. Bischoff
EPA-HQ-OAR-2002-0058-3061	S.Gworek
EPA-HQ-OAR-2002-0058-3062	S. Kennedy
EPA-HQ-OAR-2002-0058-3063	S. Sorin
EPA-HQ-OAR-2002-0058-3064	T. Thomas
EPA-HQ-OAR-2002-0058-3065	T. Cook
EPA-HQ-OAR-2002-0058-3066	T. Cardos
EPA-HQ-OAR-2002-0058-3067	A. Moore
EPA-HQ-OAR-2002-0058-3068	S. Morrow
EPA-HQ-OAR-2002-0058-3069	W. Schoene
EPA-HQ-OAR-2002-0058-3070	J. Poulton
EPA-HQ-OAR-2002-0058-3071	M. H. Miller,
EPA-HQ-OAR-2002-0058-3072	M. Lefebvre
EPA-HQ-OAR-2002-0058-3073	R. Silverman
EPA-HQ-OAR-2002-0058-3074	J. Redpath
EPA-HQ-OAR-2002-0058-3075	L. Guthrie
EPA-HQ-OAR-2002-0058-3076	J. Viacrucis
EPA-HQ-OAR-2002-0058-3077	C. Basciano
EPA-HQ-OAR-2002-0058-3078	M. Rogalski
EPA-HQ-OAR-2002-0058-3079	R. Soldano
EPA-HQ-OAR-2002-0058-3080	J. LaChapelle
EPA-HQ-OAR-2002-0058-3081	A. Parks
EPA-HQ-OAR-2002-0058-3082	K. Hennigan
EPA-HQ-OAR-2002-0058-3083	M. Groves
EPA-HQ-OAR-2002-0058-3084	E. Hecker
EPA-HQ-OAR-2002-0058-3085	E. Kuch
EPA-HQ-OAR-2002-0058-3086	M. Alsentzer
EPA-HQ-OAR-2002-0058-3087	P. Ward
EPA-HQ-OAR-2002-0058-3088	K. Pape
EPA-HQ-OAR-2002-0058-3089	C. Horner
EPA-HQ-OAR-2002-0058-3090	B. Carater
EPA-HQ-OAR-2002-0058-3091	H. Larson
EPA-HQ-OAR-2002-0058-3092	V. Jones
EPA-HQ-OAR-2002-0058-3093	L. McIntyre
EPA-HQ-OAR-2002-0058-3094	P. O'Byrne
EPA-HQ-OAR-2002-0058-3095	J. L. Mazztelli
EPA-HQ-OAR-2002-0058-3096	J. Sears
EPA-HQ-OAR-2002-0058-3097	E. Gachesa
EPA-HQ-OAR-2002-0058-3098	E. Carter
EPA-HQ-OAR-2002-0058-3099	B. Baxter
EPA-HQ-OAR-2002-0058-3100	M. Rausch
EPA-HQ-OAR-2002-0058-3101	M. Fitzgerald
EPA-HQ-OAR-2002-0058-3102	A. Cisney
EPA-HQ-OAR-2002-0058-3103	B. Culp
EPA-HQ-OAR-2002-0058-3104	C. Tansey
EPA-HQ-OAR-2002-0058-3105	C. Arndt

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EPA-HQ-OAR-2002-0058-3106	D. Scott
EPA-HQ-OAR-2002-0058-3107	A. Dew
EPA-HQ-OAR-2002-0058-3108	D. & S. Ryan
EPA-HQ-OAR-2002-0058-3109	D. Baker
EPA-HQ-OAR-2002-0058-3110	D. Jentgen
EPA-HQ-OAR-2002-0058-3111	E. Albright
EPA-HQ-OAR-2002-0058-3112	F. Kongable
EPA-HQ-OAR-2002-0058-3113	Dr. F. Gilbert
EPA-HQ-OAR-2002-0058-3114	F. Scheuer
EPA-HQ-OAR-2002-0058-3115	G. Fridlund
EPA-HQ-OAR-2002-0058-3116	J. & S. Cooper
EPA-HQ-OAR-2002-0058-3117.1	Kip Howlett, President, Hardwood Plywood and Veneer Association (HPVA)
EPA-HQ-OAR-2002-0058-3118.1	Steve Smith, Manager, Environmental Issues, LyondellBasell Industries
EPA-HQ-OAR-2002-0058-3119.1	Gregory A. Wilkins, Manager, Environmental Support, Marathon Petroleum Company LLC
EPA-HQ-OAR-2002-0058-3120.1	Patrick Strauch, Executive Director, Maine Forest Products Council
EPA-HQ-OAR-2002-0058-3121.1	Mike Robertson, on behalf of the Environment & Natural Resources policy Committee, Minnesota Chamber of Commerce
EPA-HQ-OAR-2002-0058-3122	David O'Keefe, Director, Power Operation and Business Planning, USEC
EPA-HQ-OAR-2002-0058-3123	Joe Lynch, Senior Environmental Engineer, Verso Bucksport LLC
EPA-HQ-OAR-2002-0058-3124	Mary Sullivan Douglas on behalf of National Association of Clean Air Agencies (NACAA)
EPA-HQ-OAR-2002-0058-3125	Michael J. Burns, Senior Vice President-Operations, Ever-Green, LLC for District Energy St. Paul, Inc.
EPA-HQ-OAR-2002-0058-3126	Michael J. Burns, Senior Vice President-Operations, Ever-Green Energy, LLC.
EPA-HQ-OAR-2002-0058-3127	Tom Siegrist, Director of Environmental Compliance, Koch Nitrogen Company, LLC (KNC)
EPA-HQ-OAR-2002-0058-3128	Edward Bortz, Mill Manager, SP Newsprint Co., LLC
EPA-HQ-OAR-2002-0058-3129	Byron T. Burrows, PE, BCEE, Manager-Air Programs, Tampa Electric Company
EPA-HQ-OAR-2002-0058-3130	W. Wicks
EPA-HQ-OAR-2002-0058-3131	L. Hein
EPA-HQ-OAR-2002-0058-3132	Dr. L. Glesne
EPA-HQ-OAR-2002-0058-3133	Dr. M. Thomas
EPA-HQ-OAR-2002-0058-3134	M. A. & F. Graffagnino
EPA-HQ-OAR-2002-0058-3135	M. Markus
EPA-HQ-OAR-2002-0058-3136	Late William Turley, Executive Director, Construction Materials Recycling Association (CMRA)
EPA-HQ-OAR-2002-0058-3137.1	Stephen R. Gossett, Senior Environmental Associate, Eastman Chemical Company
EPA-HQ-OAR-2002-0058-3137.2	Stephen R. Gossett, Senior Environmental Associate, Eastman Chemical Company
EPA-HQ-OAR-2002-0058-3138	Tom Brotherman, Environmental Analyst, CPS Energy
EPA-HQ-OAR-2002-0058-3139	Wilson Jones, Jr., President et al., J.W. Jones Lumber Company, Inc.
EPA-HQ-OAR-2002-0058-3140	Comment submitted Terry L. O'Clair, P.E., Director, Division of Air Quality, North Dakota Department of Health
EPA-HQ-OAR-2002-0058-3141	Dave Copeland, PE., Manager-Air Quality, Corporate Safety and Environmental Services, Praxair, Inc.
EPA-HQ-OAR-2002-0058-3142	K. Frantom
EPA-HQ-OAR-2002-0058-3143	Carrole Jackson, Purchasing Manager, Port Townsend Paper Corporation
EPA-HQ-OAR-2002-0058-3144	D. Rhodes
EPA-HQ-OAR-2002-0058-3145.1	Brian Mooney, Manager, Environment, U.S. Operations, AbitibiBowater Inc.
EPA-HQ-OAR-2002-0058-3146	James Humphries, Environmental Engineer, KapStone Kraft Paper Corporation
EPA-HQ-OAR-2002-0058-3147	J. Swindle
EPA-HQ-OAR-2002-0058-3148	John Benson, Director of Marketing, KapStone Charleston Kraft LLC
EPA-HQ-OAR-2002-0058-3149.1	Joseph Vaughn, Vice President, General Manager, Abitibibowater, Inc..
EPA-HQ-OAR-2002-0058-3150	Comment Mary Lee Ransmeier, Environmental Programs Manager, KapStone Kraft Paper Corporation
EPA-HQ-OAR-2002-0058-3151.1	Wade H. Taylor, General Manager, Abitibibowater, Inc.
EPA-HQ-OAR-2002-0058-3152	Robert Slocum, Executive Vice President, North Carolina Forestry Association
EPA-HQ-OAR-2002-0058-3153.1	Jay Backus, General Manager, Augusta Newsprint Company
EPA-HQ-OAR-2002-0058-3154.1	Jacquelyn Taylor, Chair, South Carolina Pulp and Paper Association (SCPPA)
EPA-HQ-OAR-2002-0058-3155.1	John Donahue, Vice President Manufacturing, Sappi Fine Paper North America
EPA-HQ-OAR-2002-0058-3156	S. Stuart
EPA-HQ-OAR-2002-0058-3157	Mass Comment Campaign sponsoring organization unknown (190)
EPA-HQ-OAR-2002-0058-3158	Mass Comment Campaign sponsored by Packaging Corporation of America (312)
EPA-HQ-OAR-2002-0058-3159	C. V. Asten
EPA-HQ-OAR-2002-0058-3160	D. Madlung

Document ID	Document Title
EPA-HQ-OAR-2002-0058-3161	Gene Barr, Vice President, Government and Public Affairs, Pennsylvania Chamber of Business and Industry
EPA-HQ-OAR-2002-0058-3162	Chelly Reesman, Environmental Engineer IV, J.R. Simplot Company
EPA-HQ-OAR-2002-0058-3163	Allyn Ford, President, Roseburg Forest Products
EPA-HQ-OAR-2002-0058-3164	Paul J. Allen, Senior Vice President, Corporate Affairs Division, Chief Environmental Officer, Constellation Energy
EPA-HQ-OAR-2002-0058-3165	A. D'Amico
EPA-HQ-OAR-2002-0058-3166	M. Mathews
EPA-HQ-OAR-2002-0058-3167	A. Kolter
EPA-HQ-OAR-2002-0058-3168	B. Naber
EPA-HQ-OAR-2002-0058-3169	B. Hanlon
EPA-HQ-OAR-2002-0058-3170	Dr. B. O'Donnell
EPA-HQ-OAR-2002-0058-3171	Duane Mummert, P.E., Air Subcommittee Chair, South Carolina Chamber of Commerce Environmental Technical Committee (ETC)
EPA-HQ-OAR-2002-0058-3172	Wayne Brandt, Executive Vice President, Minnesota Forest Industries (MFI)
EPA-HQ-OAR-2002-0058-3173	James L. Kavanaugh, Director, Department of Natural Resources, State of Missouri
EPA-HQ-OAR-2002-0058-3174	John Steber, HSE Leader, Performance Fibers
EPA-HQ-OAR-2002-0058-3175	Kirby Juntila, Executive Director, Marquette Board of Light & Power
EPA-HQ-OAR-2002-0058-3176.2	John Lyons, Director, Division for Air Quality, Kentucky Department for Environmental Protection
EPA-HQ-OAR-2002-0058-3177.1	Allen Sanders, Vice President and Resident Manager, Coosa Pines Operations, AbitibiBowater et al.
EPA-HQ-OAR-2002-0058-3178	Frederick W. Lash, Lead Environmental Specialist, TGEE Environmental Permitting, Air Products and Chemicals, Inc.
EPA-HQ-OAR-2002-0058-3179	David W. Peightal, Environmental Manager, Dakota Gasification Company (DGC)
EPA-HQ-OAR-2002-0058-3180	Garrett D. Tinsman, EVA, Operations, Sauder Woodworking Co.
EPA-HQ-OAR-2002-0058-3181	Michael Porter, Director, Global Environment Health and Safety (EHS) Compliance, The Goodyear Tire & Rubber Company
EPA-HQ-OAR-2002-0058-3182	Terry Charles, Environmental, Health and Safety Unit Leader, Domtar Paper Company, LLC
EPA-HQ-OAR-2002-0058-3183	Robert C. Carroll, Vice President, Renovar Energy Corporation
EPA-HQ-OAR-2002-0058-3184	Late Sherry Gee, Roanoke Rapids Mill Controller, KapStone Kraft Paper Corporation
EPA-HQ-OAR-2002-0058-3185.1	Russell Wanke, Vice-President and General Manager, Thilmany LLC
EPA-HQ-OAR-2002-0058-3185.2	Russell Wanke, Vice-President and General Manager, Thilmany LLC
EPA-HQ-OAR-2002-0058-3186.1	Late Robert Bauer, Executive Director, Kentucky Forest Industries Association
EPA-HQ-OAR-2002-0058-3187.1	Clean Air Task Force et al.
EPA-HQ-OAR-2002-0058-3187.10	Clean Air Task Force et al. (Exhibit III-7)
EPA-HQ-OAR-2002-0058-3187.11	Clean Air Task Force et al. (Exhibit III-8)
EPA-HQ-OAR-2002-0058-3187.12	Clean Air Task Force et al. (Exhibit III-9)
EPA-HQ-OAR-2002-0058-3187.13	Clean Air Task Force et al. (Exhibit III-10)
EPA-HQ-OAR-2002-0058-3187.14	Clean Air Task Force et al. (Exhibit III-11)
EPA-HQ-OAR-2002-0058-3187.15	Clean Air Task Force et al. (Exhibit III-12)
EPA-HQ-OAR-2002-0058-3187.16	Clean Air Task Force et al. (Exhibit III-13)
EPA-HQ-OAR-2002-0058-3187.2	Clean Air Task Force et al. (Appendix IV-1)
EPA-HQ-OAR-2002-0058-3187.3	Clean Air Task Force et al. (Appendix IV-2)
EPA-HQ-OAR-2002-0058-3187.4	Clean Air Task Force et al. (Exhibit III-1)
EPA-HQ-OAR-2002-0058-3187.5	Clean Air Task Force et al. (Exhibit III-2)
EPA-HQ-OAR-2002-0058-3187.6	Clean Air Task Force et al. (Exhibit III-3)
EPA-HQ-OAR-2002-0058-3187.7	Clean Air Task Force et al. (Exhibit III-4)
EPA-HQ-OAR-2002-0058-3187.8	Clean Air Task Force et al. (Exhibit III-5)
EPA-HQ-OAR-2002-0058-3187.9	Clean Air Task Force et al. (Exhibit III-6)
EPA-HQ-OAR-2002-0058-3188	Robert G. Hedden, Executive Director, Oilheat Manufacturers Association (OMA)
EPA-HQ-OAR-2002-0058-3189	Late Cheryl Sonnier Nolan, Assistant Secretary, Louisiana Department of Environmental Quality (LDEQ)
EPA-HQ-OAR-2002-0058-3189.1	Late Cheryl Sonnier Nolan, Assistant Secretary, Louisiana Department of Environmental Quality (LDEQ)
EPA-HQ-OAR-2002-0058-3190	Late Catherine Reheis-Boyd, President, Western States Petroleum Association (WSPA)
EPA-HQ-OAR-2002-0058-3190.1	Late Catherine Reheis-Boyd, President, Western States Petroleum Association (WSPA)
EPA-HQ-OAR-2002-0058-3191	Albert A. Carter, Chairman, Office of County Commissioners, Grays Harbor County, State of Washington et al.
EPA-HQ-OAR-2002-0058-3192	Frederick G. Heath, Vice President, Brown Wood Preserving Co., Inc.
EPA-HQ-OAR-2002-0058-3193	Late Bobby B. Howell, District 46, Mississippi House of Representatives
EPA-HQ-OAR-2002-0058-3194	Chuck Roady, Vice President and General Manager, F.H. Stoltze Land & Lumber Company
EPA-HQ-OAR-2002-0058-3195	J. M. (Mike) Forrest, VP and General Manager, AbitibiBowater
EPA-HQ-OAR-2002-0058-3196	Sean M. O'Keefe, Director, Environmental Affairs, Alexander & Baldwin, Inc (A&B)
EPA-HQ-OAR-2002-0058-3197	Late P. Gettinger
EPA-HQ-OAR-2002-0058-3198	Derril Marshall, P.E., General Manager, Fremont Nebraska Department of Utilities (FDU)

Document ID	Document Title
EPA-HQ-OAR-2002-0058-3199	Mass Comment Campaign sponsored by Abitibi Bowater Inc. (1,242)
EPA-HQ-OAR-2002-0058-3200	Mass Comment Campaign sponsored by Packaging Corporation of America (199)
EPA-HQ-OAR-2002-0058-3201	Mass Comment Campaign sponsoring organization unkown (18,596)
EPA-HQ-OAR-2002-0058-3202	Mass Comment Campaign sponsored by Thilmany Paper (258)
EPA-HQ-OAR-2002-0058-3203	Michael E. Case, President and Chief Executive Officer (CEO), The Westervelt Company
EPA-HQ-OAR-2002-0058-3204	Cindy Domenico, Chair, Board of County Commissioners, Boulder County
EPA-HQ-OAR-2002-0058-3205	R. Staff
EPA-HQ-OAR-2002-0058-3206	Late Cindy Eveler, President, Lincoln Area Chamber of Commerce
EPA-HQ-OAR-2002-0058-3210.1	Mitchell Leu, Environmental Engineer, Plum Creek Timber Company, Inc.
EPA-HQ-OAR-2002-0058-3211.1	Late Joseph M. Cloutier, President & CEO, RE-Gen, LLC and Renewable Energy Fuels, LLC
EPA-HQ-OAR-2002-0058-3212.1	Robert W. Glowinski, President, American Wood Council (AWC)
EPA-HQ-OAR-2002-0058-3212.2	Robert W. Glowinski, President, American Wood Council (AWC)
EPA-HQ-OAR-2002-0058-3213.1	Paul Noe, Vice President, Public Policy, American Forest & Paper Association (AF&PA)
EPA-HQ-OAR-2002-0058-3213.2	Paul Noe, Vice President, Public Policy, American Forest & Paper Association (AF&PA)
EPA-HQ-OAR-2002-0058-3214	Mass Comment Campaign sponsoring organization unknown (11)
EPA-HQ-OAR-2002-0058-3215	Late Mass Comment Campaign sponsored by Smurfit-Stone Container Corp. (59)
EPA-HQ-OAR-2002-0058-3216	Late Joseph J. Croce, Senior Vice President, Virginia Manufacturers Association (VMA)
EPA-HQ-OAR-2002-0058-3217	Frank V. Avent, III, Chairman, Halifax County, North Carolina
EPA-HQ-OAR-2002-0058-3218	Grady W. Phil Hux, President, Halifax Horizons
EPA-HQ-OAR-2002-0058-3219	Tony N. Brown, County Manager, State of North Carolina, County of Halifax
EPA-HQ-OAR-2002-0058-3220	Wayne Brandt, Executive Vice President, Minnesota Forest Industries (MFI) (Complete version of OAR-2002-0058-3172)
EPA-HQ-OAR-2002-0058-3222	Late comment submitted by Robert Ellerhorst, Director of Utilities, Power and Water Department, Michigan State University (MSU)
EPA-HQ-OAR-2002-0058-3222.1	University (MSU)
EPA-HQ-OAR-2002-0058-3222.2	University (MSU)
EPA-HQ-OAR-2002-0058-3223	Comment submitted by S. Jordan
EPA-HQ-OAR-2002-0058-3224	Late comment submitted by Marsal Martin, Plant Engineer, Exeter Energy Limited Partnership
EPA-HQ-OAR-2002-0058-3224.1	Late comment attachment submitted by Marsal Martin, Plant Engineer, Exeter Energy Limited Partnership
EPA-HQ-OAR-2002-0058-3225	Late comment submitted by James Hallett, President, Port Angeles Regional Chamber of Commerce, Port Angeles, Washington
EPA-HQ-OAR-2002-0058-3226	Late comment submitted by Terry L. Coughlin, Manager, Air Quality, Wisconsin Electric Power Company (dba, We Energies)
EPA-HQ-OAR-2002-0058-3226.1	Energies)
EPA-HQ-OAR-2002-0058-3227	Late comment submitted by Terry L. Coughlin, Manager Air Quality, Wisconsin Electric Power Company (dba, We Energies)
EPA-HQ-OAR-2002-0058-3227.1	Energies)
EPA-HQ-OAR-2002-0058-3233	Late Comment submitted by D. Bone
EPA-HQ-OAR-2002-0058-3234	Late comment submitted by Christopher S. Colman, Deputy General Counsel, Hess Corporation on behalf of HOVENSA L.L.C.
EPA-HQ-OAR-2002-0058-3234.1	L.L.C.

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AF&PA (67)	EPA-HQ-OAR-2002-0058-2386.1
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AF&PA (67)	EPA-HQ-OAR-2002-0058-2902.1
AF&PA (67)	EPA-HQ-OAR-2002-0058-2911.1
AF&PA (67)	EPA-HQ-OAR-2002-0058-2922

Table 2. Form Letters Submitted to EPA-HQ-OAR-2002-0058

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AF&PA (67)	EPA-HQ-OAR-2002-0058-3117.1
AF&PA (67)	EPA-HQ-OAR-2002-0058-3123
AF&PA (67)	EPA-HQ-OAR-2002-0058-3145.1
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AF&PA (67)	EPA-HQ-OAR-2002-0058-3195
AF&PA (67)	EPA-HQ-OAR-2002-0058-3203
AF&PA (67)	EPA-HQ-OAR-2002-0058-3210.1
Biofuel Watch (2)	EPA-HQ-OAR-2002-0058-2805.1
Biofuel Watch (2)	EPA-HQ-OAR-2002-0058-2951
Biomass Industry (5)	EPA-HQ-OAR-2002-0058-2634.1
Biomass Industry (5)	EPA-HQ-OAR-2002-0058-2701.1
Biomass Industry (5)	EPA-HQ-OAR-2002-0058-0849.1
Biomass Industry (5)	EPA-HQ-OAR-2002-0058-0853.1
Biomass Industry (5)	EPA-HQ-OAR-2002-0058-0855.1
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-0850
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Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-1916
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-1917
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-1918
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-1919
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-1920
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-1921
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-1922
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-1923
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-1924
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-1925
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-1926
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-1927
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-1928
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-1929
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-1930
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-1931
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-1932
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-1933
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-1934
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-1935
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-1936

Table 2. Form Letters Submitted to EPA-HQ-OAR-2002-0058

Form Letter Group	DCN:
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-1937
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-1938
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-1939
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-1940
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-1941
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-1942
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-1943
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-1944
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-1945
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-1946
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-1947
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-1948
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-1949
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-1950
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-1951
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-1952
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-1953
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-1954
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-1955
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-1956
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-1957
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-1958
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-1959
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-1960
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-1961
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-1962
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-1963
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-1964
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-1965
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-1966
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-1967
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-1968
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-1969
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-1970
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-1971
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-1972
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-1973
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-1974
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-1977
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-1978
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-1979
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-1980
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-1981
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-1982
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-1983
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-1984

Form Letter Group	DCN:
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-1985
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-1986
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-1987
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-1988
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-1989
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-1990
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-1991
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-1992
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-1993
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-1994
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-1995
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-1996
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-1997
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-1998
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-1999
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2000
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2001
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2002
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2003
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2004
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2005
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2006
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2008
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2009
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2010
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2011
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2012
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2013
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2014
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2015
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2016
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2017
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2018
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2019
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2020
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2021
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2022
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2023
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2024
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2025
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2026
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2027
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2028
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2029
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2030
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2031

Form Letter Group	DCN:
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2032
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2033
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2034
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2035
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2036
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2037
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2038
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2039
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2040
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2041
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2042
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2043
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2044
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2045
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2046
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2047
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2048
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2049
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2050
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2051
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2052
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2053
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2054
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2055
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2056
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2057
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2058
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2059
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2060
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2061
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2062
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2063
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2064
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2066
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2067
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2068
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2069
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2070
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2071
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2072
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2073
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2074
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2075
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2076
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2077
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2078

Form Letter Group	DCN:
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2079
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2080
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2081
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2082
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2083
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2084
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2085
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2087
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2088
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2089
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2090
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2091
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2092
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2093
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2094
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2096
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2099
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2100
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2101
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2103
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2104
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2105
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2106
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2107
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2108
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2109
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2110
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2111
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2112
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2113
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2114
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2115
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2116
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2117
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2118
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2119
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2121
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2125
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2126
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2127
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2128
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2130
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2131
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2132
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2133
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2134

Form Letter Group	DCN:
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2135
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2136
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2137
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2138
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2139
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2140
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2141
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2142
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2143
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2144
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2145
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2146
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2147
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2148
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2149
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2150
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2151
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2152
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2153
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2154
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2155
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2158
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2160
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2161
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2163
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2164
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2165
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2166
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2167
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2168
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2169
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2170
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2171
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2172
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2173
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2174
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2175
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2176
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2177
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2178
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2179
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2180
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2181
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2182
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2183
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2184

Form Letter Group	DCN:
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2185
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2186
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2187
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2188
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2189
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2190
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2191
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2192
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2193
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2194
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2195
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2196
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2197
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2198
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2199
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2200
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2201
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2202
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2203
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2205
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2206
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2208
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2209
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2210
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2211
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2212
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2213
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2214
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2215
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2216
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2217
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2218
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2219
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2220
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2221
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2222
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2223
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2224
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2225
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2226
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2227
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2228
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2229
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2230
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2231
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2232

Form Letter Group	DCN:
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2233
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2234
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2235
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2236
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2237
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2238
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2239
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2240
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2241
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2242
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2243
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2244
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2245
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2246
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2247
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2248
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2249
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2250
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2251
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2252
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2253
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2255
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2256
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2257
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2258
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2259
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2260
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2261
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2262
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2263
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2264
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2265
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2266
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2267
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2268
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2269
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2270
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2271
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2272
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2273
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2274
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2275
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2276
Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2277
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Concerned Citizens (530)	EPA-HQ-OAR-2002-0058-2460
Evergreen Energy (2)	EPA-HQ-OAR-2002-0058-3125
Evergreen Energy (2)	EPA-HQ-OAR-2002-0058-3126
ExtensionofComment (2)	EPA-HQ-OAR-2002-0058-0852.1
ExtensionofComment (2)	EPA-HQ-OAR-2002-0058-2702.3-EPA response to comment
Flakeboard (6)	EPA-HQ-OAR-2002-0058-2836
Flakeboard (6)	EPA-HQ-OAR-2002-0058-2838.1
Flakeboard (6)	EPA-HQ-OAR-2002-0058-2858.1
Flakeboard (6)	EPA-HQ-OAR-2002-0058-2915.1
Flakeboard (6)	EPA-HQ-OAR-2002-0058-2919.1
Flakeboard (6)	EPA-HQ-OAR-2002-0058-2939.1
Flambeau River Papers (29)	EPA-HQ-OAR-2002-0058-1753.1
Flambeau River Papers (29)	EPA-HQ-OAR-2002-0058-1754.1
Flambeau River Papers (29)	EPA-HQ-OAR-2002-0058-1755.1
Flambeau River Papers (29)	EPA-HQ-OAR-2002-0058-1756.1
Flambeau River Papers (29)	EPA-HQ-OAR-2002-0058-1839.1
Flambeau River Papers (29)	EPA-HQ-OAR-2002-0058-1849.1
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Flambeau River Papers (29)	EPA-HQ-OAR-2002-0058-1880.1
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Flambeau River Papers (29)	EPA-HQ-OAR-2002-0058-2254.1
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Flambeau River Papers (29)	EPA-HQ-OAR-2002-0058-3150
Flambeau River Papers (29)	EPA-HQ-OAR-2002-0058-3157
Flambeau River Papers (29)	EPA-HQ-OAR-2002-0058-3184
Florida Biomass (2)	EPA-HQ-OAR-2002-0058-1845

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Mass Campaigns (4)	EPA-HQ-OAR-2002-0058-3200
Mass Campaigns (4)	EPA-HQ-OAR-2002-0058-3201
Mass Campaigns (4)	EPA-HQ-OAR-2002-0058-3202
Pole & Piling Co (3)	EPA-HQ-OAR-2002-0058-2404.1
Pole & Piling Co (3)	EPA-HQ-OAR-2002-0058-2414.1
Pole & Piling Co (3)	EPA-HQ-OAR-2002-0058-2464
Southern Company (3)	EPA-HQ-OAR-2002-0058-2741.1
Southern Company (3)	EPA-HQ-OAR-2002-0058-2923 and 2923.1
Southern Company (3)	EPA-HQ-OAR-2002-0058-2924 and 2924.1
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Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1313
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1314
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1315
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1316
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1317
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1318
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1319
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1320
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1321
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1322
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1323
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1324
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1325
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1326
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1327
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1328
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1329
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1330
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1331
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1332
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1333
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1334
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1335
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1336
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1337
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1338
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1339
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1340
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1341
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1342
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1343
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1344
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1345
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1346
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1347
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1348
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1349
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1350
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1351

Form Letter Group	DCN:
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1352
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1353
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1354
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1355
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1356
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1357
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1358
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1359
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1360
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1361
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1362
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1363
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1364
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1365
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1366
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1367
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1368
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1369
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1370
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1371
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1372
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1373
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1374
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1375
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1376
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1377
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1378
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1379
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1380
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1381
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1382
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1383
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1384
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1385
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1386
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1387
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1389
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1390
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1391
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1392
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1393
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1394
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1395
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1396
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1397
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1398

Table 2. Form Letters Submitted to EPA-HQ-OAR-2002-0058

Form Letter Group	DCN:
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1399
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1400
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1401
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1402
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1403
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1404
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1405
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1406
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1407
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1408
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1409
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1410
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1411
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1412
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1413
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1414
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1415
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1416
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1417
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1418
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1419
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1420
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1421
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1422
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1423
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1424
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1426
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1427
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1428
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1429
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1430
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1431
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1432
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1433
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1434
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1435
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1436
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1437
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1438
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1439
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1440
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1441
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1442
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1443
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1444
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1445

Form Letter Group	DCN:
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1446
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1447
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1448
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1449
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1450
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1451
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1452
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1453
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1454
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1455
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1456
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1457
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1458
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1459
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1460
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1461
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1462
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1463
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1464
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1465
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1466
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1467
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1468
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1469
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1470
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1471
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1472
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1473
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1474
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1475
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1476
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1477
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1478
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1479
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1480
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1481
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1482
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1483
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1484
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1485
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1486
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1487
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1488
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1489
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1490
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1491

Form Letter Group	DCN:
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1492
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1493
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1494
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1495
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1496
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1497
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1498
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1499
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1500
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1501
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1502
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1503
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1504
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1505
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1506
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1507
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1508
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1509
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1510
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1511
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1512
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1513
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1514
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1515
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1516
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1517
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1518
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1519
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1520
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1521
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1522
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1523
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1524
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1525
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1526
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1527
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1528
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1529
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1530
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1531
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1532
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1533
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1534
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1535
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1536
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1538

Form Letter Group	DCN:
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1539
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1540
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1541
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1542
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1543
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1544
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1545
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1546
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1547
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1548
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1549
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1550
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1551
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1552
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1553
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1554
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1555
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1556
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1557
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1558
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1559
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1560
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1561
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1562
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1563
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1564
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1565
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1566
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1567
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1568
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1569
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1570
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1571
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1572
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1573
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1574
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1575
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1576
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1577
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1578
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1579
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1580
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1581
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1582
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1583
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1584

Form Letter Group	DCN:
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1585
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1586
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1587
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1588
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1589
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1590
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1591
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1592
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1593
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1594
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1595
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1605
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1606
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1607
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1608
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1609
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1610
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1611
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1612
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1613
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1614
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1615
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1616
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1617
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1618
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1619
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1620
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1621
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1622
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1623
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1624
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Form Letter Group	DCN:
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Form Letter Group	DCN:
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Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-1791
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2086
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Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2159
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Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2291
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2292
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2293
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Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2397
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Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2476
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Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2481
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Form Letter Group	DCN:
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Form Letter Group	DCN:
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Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2544
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2545
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2546
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2547
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2548
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2549
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2550
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2551
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2552
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2553
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2554
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2555
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2556
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2557
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2558
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2559
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2560
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2561
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2562
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2563
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2564
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2565
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2566
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2567
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2568
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2569
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2570
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2571
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2572
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2573
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2574
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2575
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2576
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2577
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2578
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2579
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2580
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2581
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2582

Form Letter Group	DCN:
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2583
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2584
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2585
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2586
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2587
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2588
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2589
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2590
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2591
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2592
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2593
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2594
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2595
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2596
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2597
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2598
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2604
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2605
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2606
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2607
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2608
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2609
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2610
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2611
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2612
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2613
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2614
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2615
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2616
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2617
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2618
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2619
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2620
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2621
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2622
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2623
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2624
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2625
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2626
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2627
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2628
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2629
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2636
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2637
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2638
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2639

Form Letter Group	DCN:
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2640
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Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2642
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2643
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2644
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2645
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2646
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2647
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2648
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2649
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2650
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2651
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2652
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2653
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2654
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2655
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2656
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2657
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2658
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2659
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2660
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2661
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2662
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2663
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2664
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2665
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2666
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2667
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2668
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2669
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2670
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2671
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2677
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2678
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2680
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2682
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2683
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2684
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2685
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2686
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2687
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2688
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2971
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2972
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2974
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2975

Form Letter Group	DCN:
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2976
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2978
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2979
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2980
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2981
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2982
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2983
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2984
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2985
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2988
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2989
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2990
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2991
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2993
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-2994
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3000
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3001
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3002
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3003
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3004
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3005
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3006
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3007
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3008
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3009
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3010
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3011
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3012
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3013
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3014
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3015
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3016
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3017
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3018
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3019
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3020
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3021
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3022
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3023
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3024
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3025
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3026
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3027
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3028
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3029
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3030

Form Letter Group	DCN:
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3031
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3032
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3033
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3034
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3035
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3036
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3037
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3038
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3039
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3040
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3041
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3042
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3043
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3044
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3045
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3046
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3047
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3048
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3049
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3050
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3051
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3052
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3053
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3054
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3055
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3056
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3057
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3058
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3059
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3060
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3061
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3062
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3063
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3064
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3065
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3066
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3067
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3068
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3069
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3070
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3071
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3072
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3073
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3074
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3075
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3076

Form Letter Group	DCN:
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3077
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3078
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3079
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3080
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3081
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3082
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3083
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3084
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3085
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3086
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3087
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3088
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3089
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3090
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3091
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3092
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3093
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3094
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3095
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3096
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3097
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3098
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3099
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3100
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3101
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3102
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3103
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3104
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3105
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3106
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3107
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3108
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3109
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3110
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3111
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3112
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3113
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3114
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3115
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3116
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3131
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3132
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3133
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3134
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3135
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3165

Table 2. Form Letters Submitted to EPA-HQ-OAR-2002-0058

Form Letter Group	DCN:
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3166
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3167
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3168
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3169
Sierra club form letter (1328)	EPA-HQ-OAR-2002-0058-3170
SierraClub modified form letter (2)	EPA-HQ-OAR-2002-0058-2977
SierraClub modified form letter (2)	EPA-HQ-OAR-2002-0058-2992
Small Utilities (2)	EPA-HQ-OAR-2002-0058-2962.1
Small Utilities (2)	EPA-HQ-OAR-2002-0058-3198

Table 3. Comments that reference other commentors, submitted to EPA-HQ-OAR-2002-0058

Comment	DCN Containing Reference	Comment Referenced or Incorporated by Reference	DCN of IBR letter
Shell Chemical LP, Geismar Plant	EPA-HQ-OAR-2002-0058-1873	ACC	EPA-HQ-OAR-2002-0058-2792.1
The Dow Chemical Company	EPA-HQ-OAR-2002-0058-2632.1	ACC	EPA-HQ-OAR-2002-0058-2792.1
American Public Power Association (APPA)	EPA-HQ-OAR-2002-0058-2714.1	ACC	EPA-HQ-OAR-2002-0058-2792.1
Arkema	EPA-HQ-OAR-2002-0058-2751.1	ACC	EPA-HQ-OAR-2002-0058-2792.1
Monsanto	EPA-HQ-OAR-2002-0058-2754.1	ACC	EPA-HQ-OAR-2002-0058-2792.1
DuPont Engineering Research and Technology	EPA-HQ-OAR-2002-0058-2793.1	ACC	EPA-HQ-OAR-2002-0058-2792.1
Celanese International Corporation	EPA-HQ-OAR-2002-0058-2840.1	ACC	EPA-HQ-OAR-2002-0058-2792.1
Occidental Chemical Corporation (OCC)	EPA-HQ-OAR-2002-0058-2848	ACC	EPA-HQ-OAR-2002-0058-2792.1
Georgia Industry Environmental Coalition (GEIC)	EPA-HQ-OAR-2002-0058-2882.1	ACC	EPA-HQ-OAR-2002-0058-2792.1
American Coatings Association (ACA)	EPA-HQ-OAR-2002-0058-2886.1	ACC	EPA-HQ-OAR-2002-0058-2792.1
Society of Chemical Manufacturers and Affiliates (SOCMA)	EPA-HQ-OAR-2002-0058-2926.1	ACC	EPA-HQ-OAR-2002-0058-2792.1
PPG Industries, Inc.	EPA-HQ-OAR-2002-0058-2938.1	ACC	EPA-HQ-OAR-2002-0058-2792.1
The Vinyl Institute	EPA-HQ-OAR-2002-0058-2944.1	ACC	EPA-HQ-OAR-2002-0058-2792.1
ExxonMobil Refining and Supply Company	EPA-HQ-OAR-2002-0058-2968.1	ACC	EPA-HQ-OAR-2002-0058-2792.1
Marathon Petroleum Company LLC	EPA-HQ-OAR-2002-0058-3119.1	ACC	EPA-HQ-OAR-2002-0058-2792.1
Air Products and Chemicals, Inc.	EPA-HQ-OAR-2002-0058-3178	ACC	EPA-HQ-OAR-2002-0058-2792.1
Dakota Gasification Company	EPA-HQ-OAR-2002-0058-3179	ACC	EPA-HQ-OAR-2002-0058-2792.1
CraftMaster Manufacturing, Inc.	EPA-HQ-OAR-2002-0058-1907.1	AF&PA	EPA-HQ-OAR-2002-0058-3213.1
City of Park Falls, WI	EPA-HQ-OAR-2002-0058-2350.1	AF&PA	EPA-HQ-OAR-2002-0058-3213.1
Packaging Corporation of America (PCA)	EPA-HQ-OAR-2002-0058-2385	AF&PA	EPA-HQ-OAR-2002-0058-3213.1
Composite Panel Association	EPA-HQ-OAR-2002-0058-2530.1	AF&PA	EPA-HQ-OAR-2002-0058-3213.1
Decorative Panels International	EPA-HQ-OAR-2002-0058-2599.1	AF&PA	EPA-HQ-OAR-2002-0058-3213.1
Tennessee Forestry Association	EPA-HQ-OAR-2002-0058-2603.1	AF&PA	EPA-HQ-OAR-2002-0058-3213.1
Hexion Specialty Chemicals	EPA-HQ-OAR-2002-0058-2634.1	AF&PA	EPA-HQ-OAR-2002-0058-3213.1
Tennessee Paper Council (TPC)	EPA-HQ-OAR-2002-0058-2691.1	AF&PA	EPA-HQ-OAR-2002-0058-3213.1
Northwest Pulp and Paper Association (NWPPA)	EPA-HQ-OAR-2002-0058-2693.1	AF&PA	EPA-HQ-OAR-2002-0058-3213.1
P. H. Glatfelter Company	EPA-HQ-OAR-2002-0058-2694.1	AF&PA	EPA-HQ-OAR-2002-0058-3213.1
Evergreen Packaging - Canton, NC Mill	EPA-HQ-OAR-2002-0058-2696.1	AF&PA	EPA-HQ-OAR-2002-0058-3213.1
Evergreen Packaging - Canton, NC Mill	EPA-HQ-OAR-2002-0058-2696.1	AF&PA	EPA-HQ-OAR-2002-0058-3213.1
American Public Power Association (APPA)	EPA-HQ-OAR-2002-0058-2714.1	AF&PA	EPA-HQ-OAR-2002-0058-3213.1
Brick Industry Association (BIA)	EPA-HQ-OAR-2002-0058-2716.1	AF&PA	EPA-HQ-OAR-2002-0058-3213.1
Georgia-Pacific LLC	EPA-HQ-OAR-2002-0058-2745.1	AF&PA	EPA-HQ-OAR-2002-0058-3213.1
MeadWestvaco (MWV)	EPA-HQ-OAR-2002-0058-2747.1	AF&PA	EPA-HQ-OAR-2002-0058-3213.1
National Alliance of Forest Owners (NAFO)	EPA-HQ-OAR-2002-0058-2750.1	AF&PA	EPA-HQ-OAR-2002-0058-3213.1
Industrial Energy Consumers of America (IECA)	EPA-HQ-OAR-2002-0058-2752.1	AF&PA	EPA-HQ-OAR-2002-0058-3213.1
INVISTA S.à r.l.	EPA-HQ-OAR-2002-0058-2761.1	AF&PA	EPA-HQ-OAR-2002-0058-3213.1
International Paper	EPA-HQ-OAR-2002-0058-2777.1	AF&PA	EPA-HQ-OAR-2002-0058-3213.1
Smurfit-Stone Container Corporation	EPA-HQ-OAR-2002-0058-2783.1	AF&PA	EPA-HQ-OAR-2002-0058-3213.1
Weyerhaeuser	EPA-HQ-OAR-2002-0058-2797.1	AF&PA	EPA-HQ-OAR-2002-0058-3213.1
National Council for Air and Stream Improvement (NCASI)	EPA-HQ-OAR-2002-0058-2804.1	AF&PA	EPA-HQ-OAR-2002-0058-3213.1
Domtar Corporation	EPA-HQ-OAR-2002-0058-2823	AF&PA	EPA-HQ-OAR-2002-0058-3213.1
Boise Cascade	EPA-HQ-OAR-2002-0058-2825	AF&PA	EPA-HQ-OAR-2002-0058-3213.1
Kronospan LLC	EPA-HQ-OAR-2002-0058-2839	AF&PA	EPA-HQ-OAR-2002-0058-3213.1
SCA Tissue	EPA-HQ-OAR-2002-0058-2843.1	AF&PA	EPA-HQ-OAR-2002-0058-3213.1
Boise Inc.	EPA-HQ-OAR-2002-0058-2855.1	AF&PA	EPA-HQ-OAR-2002-0058-3213.1
Port Townsend Paper Corporation (PTPC)	EPA-HQ-OAR-2002-0058-2871.1	AF&PA	EPA-HQ-OAR-2002-0058-3213.1
Temple-Inland	EPA-HQ-OAR-2002-0058-2873.1	AF&PA	EPA-HQ-OAR-2002-0058-3213.1
Georgia Industry Environmental Coalition (GEIC)	EPA-HQ-OAR-2002-0058-2882.1	AF&PA	EPA-HQ-OAR-2002-0058-3213.1
Ohio Chamber of Commerce	EPA-HQ-OAR-2002-0058-2901.1	AF&PA	EPA-HQ-OAR-2002-0058-3213.1
Georgia Paper & Forest Products Association (GPFPA)	EPA-HQ-OAR-2002-0058-2905	AF&PA	EPA-HQ-OAR-2002-0058-3213.1

Table 3. Comments that reference other commentors, submitted to EPA-HQ-OAR-2002-0058

Comment	DCN Containing Reference	Comment Referenced or Incorporated by Reference	DCN of IBR letter
Pennsylvania Forest Products Association	EPA-HQ-OAR-2002-0058-2906.1	AF&PA	EPA-HQ-OAR-2002-0058-3213.1
Packaging Corporation of America (PCA)	EPA-HQ-OAR-2002-0058-2913.1	AF&PA	EPA-HQ-OAR-2002-0058-3213.1
Flakeboard America	EPA-HQ-OAR-2002-0058-2915.1	AF&PA	EPA-HQ-OAR-2002-0058-3213.1
NewPage Corporation	EPA-HQ-OAR-2002-0058-2920.1	AF&PA	EPA-HQ-OAR-2002-0058-3213.1
Oregon Forest Industries Council (OFIC)	EPA-HQ-OAR-2002-0058-2928.1	AF&PA	EPA-HQ-OAR-2002-0058-3213.1
Oregon Forest Industries Council (OFIC)	EPA-HQ-OAR-2002-0058-2928.1	AF&PA	EPA-HQ-OAR-2002-0058-3213.1
Lincoln Paper and Tissue	EPA-HQ-OAR-2002-0058-2999.1	AF&PA	EPA-HQ-OAR-2002-0058-3213.1
South Carolina Pulp & Paper Association (SCPPA)	EPA-HQ-OAR-2002-0058-3154.1	AF&PA	EPA-HQ-OAR-2002-0058-3213.1
Sauder Woodworking Co.	EPA-HQ-OAR-2002-0058-3180	AF&PA	EPA-HQ-OAR-2002-0058-3213.1
Domtar Paper Company, LLC	EPA-HQ-OAR-2002-0058-3182	AF&PA	EPA-HQ-OAR-2002-0058-3213.1
Thilmany LLC	EPA-HQ-OAR-2002-0058-3185.1	AF&PA	EPA-HQ-OAR-2002-0058-3213.1
Alexander & Baldwin, Inc (A&B)	EPA-HQ-OAR-2002-0058-3196.1	AF&PA	EPA-HQ-OAR-2002-0058-3213.1
American Wood Council (AWC)	EPA-HQ-OAR-2002-0058-3212.1	AF&PA	EPA-HQ-OAR-2002-0058-3213.1
Minnesota Forest Industries (MFI)	EPA-HQ-OAR-2002-0058-3220	AF&PA	EPA-HQ-OAR-2002-0058-3213.1
US Beet Sugar Association	EPA-HQ-OAR-2002-0058-2827.1	The Amalgamated Sugar Company LLC (TASCO)	EPA-HQ-OAR-2002-0058-2833.1
US Beet Sugar Association	EPA-HQ-OAR-2002-0058-2827.1	Company	EPA-HQ-OAR-2002-0058-2970.1
United States Steel Corporation (USS)	EPA-HQ-OAR-2002-0058-2796.1	American Iron and Steel Institute	EPA-HQ-OAR-2002-0058-2998.1
ArcelorMittal USA Inc.	EPA-HQ-OAR-2002-0058-2811.1	American Iron and Steel Institute	EPA-HQ-OAR-2002-0058-2998.1
American Gas Association (AGA) & American Public Gas Association (A	EPA-HQ-OAR-2002-0058-2724.1	America's Natural Gas Alliance (ANGA)	EPA-HQ-OAR-2002-0058-2864.1
Anadarko Petroleum Corporation	EPA-HQ-OAR-2002-0058-2909.1	America's Natural Gas Alliance (ANGA)	EPA-HQ-OAR-2002-0058-2864.1
CraftMaster Manufacturing, Inc.	EPA-HQ-OAR-2002-0058-1907.1	American Wood Council (AWC)	EPA-HQ-OAR-2002-0058-3212.1
Composite Panel Association	EPA-HQ-OAR-2002-0058-2530.1	American Wood Council (AWC)	EPA-HQ-OAR-2002-0058-3212.1
Hexion Specialty Chemicals	EPA-HQ-OAR-2002-0058-2634.1	American Wood Council (AWC)	EPA-HQ-OAR-2002-0058-3212.1
National Alliance of Forest Owners (NAFO)	EPA-HQ-OAR-2002-0058-2750.1	American Wood Council (AWC)	EPA-HQ-OAR-2002-0058-3212.1
Weyerhaeuser	EPA-HQ-OAR-2002-0058-2797.1	American Wood Council (AWC)	EPA-HQ-OAR-2002-0058-3212.1
National Council for Air and Stream Improvement (NCASI)	EPA-HQ-OAR-2002-0058-2804.1	American Wood Council (AWC)	EPA-HQ-OAR-2002-0058-3212.1
Boise Cascade	EPA-HQ-OAR-2002-0058-2825	American Wood Council (AWC)	EPA-HQ-OAR-2002-0058-3212.1
Kronospan LLC	EPA-HQ-OAR-2002-0058-2839	American Wood Council (AWC)	EPA-HQ-OAR-2002-0058-3212.1
Temple-Inland	EPA-HQ-OAR-2002-0058-2873.1	American Wood Council (AWC)	EPA-HQ-OAR-2002-0058-3212.1
Flakeboard America	EPA-HQ-OAR-2002-0058-2915.1	American Wood Council (AWC)	EPA-HQ-OAR-2002-0058-3212.1
Oregon Forest Industries Council (OFIC)	EPA-HQ-OAR-2002-0058-2928.1	American Wood Council (AWC)	EPA-HQ-OAR-2002-0058-3212.1
Oregon Forest Industries Council (OFIC)	EPA-HQ-OAR-2002-0058-2928.1	American Wood Council (AWC)	EPA-HQ-OAR-2002-0058-3212.1
Sauder Woodworking Co.	EPA-HQ-OAR-2002-0058-3180	American Wood Council (AWC)	EPA-HQ-OAR-2002-0058-3212.1
Michigan Municipal Electric Association (MMEA)	EPA-HQ-OAR-2002-0058-2795.1	American Municipal Power, Inc. (AMP)	EPA-HQ-OAR-2002-0058-2808.1
Rochester Public Utilities (RPU)	EPA-HQ-OAR-2002-0058-2850.1	American Municipal Power, Inc. (AMP)	EPA-HQ-OAR-2002-0058-2808.1
Holland Board of Public Works (HBPW), Michigan	EPA-HQ-OAR-2002-0058-2907.1	American Municipal Power, Inc. (AMP)	EPA-HQ-OAR-2002-0058-2808.1
Shell Chemical LP, Geismar Plant	EPA-HQ-OAR-2002-0058-1873	Refiners Association (NPRA)	EPA-HQ-OAR-2002-0058-0851.1
The Dow Chemical Company	EPA-HQ-OAR-2002-0058-2632.1	Refiners Association (NPRA)	EPA-HQ-OAR-2002-0058-0851.1
American Public Power Association (APPA)	EPA-HQ-OAR-2002-0058-2714.1	Refiners Association (NPRA)	EPA-HQ-OAR-2002-0058-0851.1
Lousiana Mid-Continent Oil and Gas Association (LMOGA)	EPA-HQ-OAR-2002-0058-2699.1	Refiners Association (NPRA)	EPA-HQ-OAR-2002-0058-0851.1
Brick Industry Association (BIA)	EPA-HQ-OAR-2002-0058-2716.1	Refiners Association (NPRA)	EPA-HQ-OAR-2002-0058-0851.1
Georgia-Pacific LLC	EPA-HQ-OAR-2002-0058-2745.1	Refiners Association (NPRA)	EPA-HQ-OAR-2002-0058-0851.1
ArcelorMittal USA Inc.	EPA-HQ-OAR-2002-0058-2811.1	Refiners Association (NPRA)	EPA-HQ-OAR-2002-0058-0851.1
Tesoro Companies, Inc.	EPA-HQ-OAR-2002-0058-2846.1	Refiners Association (NPRA)	EPA-HQ-OAR-2002-0058-0851.1
American Coke and Coal Chemicals Institute (ACCCI)	EPA-HQ-OAR-2002-0058-2849.1	Refiners Association (NPRA)	EPA-HQ-OAR-2002-0058-0851.1
Texas Oil & Gas Association (TxOGA)	EPA-HQ-OAR-2002-0058-2857.1	Refiners Association (NPRA)	EPA-HQ-OAR-2002-0058-0851.1
HOVENSA, LLC	EPA-HQ-OAR-2002-0058-2863.1	Refiners Association (NPRA)	EPA-HQ-OAR-2002-0058-0851.1
ConocoPhillips	EPA-HQ-OAR-2002-0058-2867.1	Refiners Association (NPRA)	EPA-HQ-OAR-2002-0058-0851.1
ExxonMobil Refining and Supply Company	EPA-HQ-OAR-2002-0058-2968.1	Refiners Association (NPRA)	EPA-HQ-OAR-2002-0058-0851.1
Gas Processors Association (GPA)	EPA-HQ-OAR-2002-0058-2986.1	Refiners Association (NPRA)	EPA-HQ-OAR-2002-0058-0851.1

Table 3. Comments that reference other commentors, submitted to EPA-HQ-OAR-2002-0058

Comment	DCN Containing Reference	Comment Referenced or Incorporated by Reference	DCN of IBR letter
Marathon Petroleum Company LLC	EPA-HQ-OAR-2002-0058-3119.1	Refiners Association (NPRA)	EPA-HQ-OAR-2002-0058-0851.1
USEC	EPA-HQ-OAR-2002-0058-3122	Refiners Association (NPRA)	EPA-HQ-OAR-2002-0058-0851.1
Air Products and Chemicals, Inc.	EPA-HQ-OAR-2002-0058-3178	Refiners Association (NPRA)	EPA-HQ-OAR-2002-0058-0851.1
Western States Petroleum Association (WSPA)	EPA-HQ-OAR-2002-0058-3190.1	Refiners Association (NPRA)	EPA-HQ-OAR-2002-0058-0851.1
Michigan Municipal Electric Association (MMEA)	EPA-HQ-OAR-2002-0058-2795.1	American Public Power Association (APPA)	EPA-HQ-OAR-2002-0058-0846.1
Manitowoc Public Utilities	EPA-HQ-OAR-2002-0058-2810.1	American Public Power Association (APPA)	EPA-HQ-OAR-2002-0058-0846.1
USEC	EPA-HQ-OAR-2002-0058-3122	American Public Power Association (APPA)	EPA-HQ-OAR-2002-0058-0846.1
GDF SUEZ Energy Generation NA, Inc. (GSEGNA)	EPA-HQ-OAR-2002-0058-2946.1	Biomass Power Association	EPA-HQ-OAR-2002-0058-2934.1
RE-Gen, LLC and Renewable Energy Fuels, LLC	EPA-HQ-OAR-2002-0058-3211.1	Biomass Power Association	EPA-HQ-OAR-2002-0058-2934.1
USEC	EPA-HQ-OAR-2002-0058-3122	CEMEX, Inc.	EPA-HQ-OAR-2002-0058-0844.1
American Public Power Association (APPA)	EPA-HQ-OAR-2002-0058-2714.1	Council Of Industrial Boiler Owners (CIBO)	EPA-HQ-OAR-2002-0058-2702
Georgia-Pacific LLC	EPA-HQ-OAR-2002-0058-2745.1	Council Of Industrial Boiler Owners (CIBO)	EPA-HQ-OAR-2002-0058-2702
Industrial Energy Consumers of America (IECA)	EPA-HQ-OAR-2002-0058-2752.1	Council Of Industrial Boiler Owners (CIBO)	EPA-HQ-OAR-2002-0058-2702
Monsanto	EPA-HQ-OAR-2002-0058-2754.1	Council Of Industrial Boiler Owners (CIBO)	EPA-HQ-OAR-2002-0058-2702
Iowa Department of Natural Resources (IDNR)	EPA-HQ-OAR-2002-0058-2767.1	Council Of Industrial Boiler Owners (CIBO)	EPA-HQ-OAR-2002-0058-2702
Group of Automotive Manufacturers (BMW Group, Chrysler Group LLC,	EPA-HQ-OAR-2002-0058-2775	Council Of Industrial Boiler Owners (CIBO)	EPA-HQ-OAR-2002-0058-2702
DuPont Engineering Research and Technology	EPA-HQ-OAR-2002-0058-2793.1	Council Of Industrial Boiler Owners (CIBO)	EPA-HQ-OAR-2002-0058-2702
Weyerhaeuser	EPA-HQ-OAR-2002-0058-2797.1	Council Of Industrial Boiler Owners (CIBO)	EPA-HQ-OAR-2002-0058-2702
Celanese International Corporation	EPA-HQ-OAR-2002-0058-2840.1	Council Of Industrial Boiler Owners (CIBO)	EPA-HQ-OAR-2002-0058-2702
Citizens Thermal	EPA-HQ-OAR-2002-0058-2875.1	Council Of Industrial Boiler Owners (CIBO)	EPA-HQ-OAR-2002-0058-2702
Georgia Industry Environmental Coalition (GEIC)	EPA-HQ-OAR-2002-0058-2882.1	Council Of Industrial Boiler Owners (CIBO)	EPA-HQ-OAR-2002-0058-2702
Morton Salt	EPA-HQ-OAR-2002-0058-2883.1	Council Of Industrial Boiler Owners (CIBO)	EPA-HQ-OAR-2002-0058-2702
International District Energy Association (IDEA)	EPA-HQ-OAR-2002-0058-2918.1	Council Of Industrial Boiler Owners (CIBO)	EPA-HQ-OAR-2002-0058-2702
Archer Daniels Midland Company (ADM)	EPA-HQ-OAR-2002-0058-2927.1	Council Of Industrial Boiler Owners (CIBO)	EPA-HQ-OAR-2002-0058-2702
PPG Industries, Inc.	EPA-HQ-OAR-2002-0058-2938.1	Council Of Industrial Boiler Owners (CIBO)	EPA-HQ-OAR-2002-0058-2702
Rubber Manufacturers Association	EPA-HQ-OAR-2002-0058-2941.1	Council Of Industrial Boiler Owners (CIBO)	EPA-HQ-OAR-2002-0058-2702
GDF SUEZ Energy Generation NA, Inc. (GSEGNA)	EPA-HQ-OAR-2002-0058-2946.1	Council Of Industrial Boiler Owners (CIBO)	EPA-HQ-OAR-2002-0058-2702
Alcoa Inc,	EPA-HQ-OAR-2002-0058-2967.1	Council Of Industrial Boiler Owners (CIBO)	EPA-HQ-OAR-2002-0058-2702
South Carolina Pulp & Paper Association (SCPPA)	EPA-HQ-OAR-2002-0058-3154.1	Council Of Industrial Boiler Owners (CIBO)	EPA-HQ-OAR-2002-0058-2702
Entergy Services, Inc.	EPA-HQ-OAR-2002-0058-2757.1	Class of 85 Regulatory Response Group	EPA-HQ-OAR-2002-0058-2802.1
Constellation Energy	EPA-HQ-OAR-2002-0058-3164	Clean Energy Group	EPA-HQ-OAR-2002-0058-2466.1
CraftMaster Manufacturing, Inc.	EPA-HQ-OAR-2002-0058-1907.1	Composite Panel Association	EPA-HQ-OAR-2002-0058-2530.1
Hexion Specialty Chemicals	EPA-HQ-OAR-2002-0058-2634.1	Composite Panel Association	EPA-HQ-OAR-2002-0058-2530.1
Boise Cascade	EPA-HQ-OAR-2002-0058-2825	Composite Panel Association	EPA-HQ-OAR-2002-0058-2530.1
Kronospan LLC	EPA-HQ-OAR-2002-0058-2839	Composite Panel Association	EPA-HQ-OAR-2002-0058-2530.1
Flakeboard America	EPA-HQ-OAR-2002-0058-2915.1	Composite Panel Association	EPA-HQ-OAR-2002-0058-2530.1
Sauder Woodworking Co.	EPA-HQ-OAR-2002-0058-3180	Composite Panel Association	EPA-HQ-OAR-2002-0058-2530.1
Domtar Paper Company, LLC	EPA-HQ-OAR-2002-0058-3182	Domtar Corporation	EPA-HQ-OAR-2002-0058-2823.1
Ameren Corporation	EPA-HQ-OAR-2002-0058-2303.1	Edison Electric Institute (EEI)	EPA-HQ-OAR-2002-0058-2755.1
Luminant	EPA-HQ-OAR-2002-0058-2780.1	Edison Electric Institute (EEI)	EPA-HQ-OAR-2002-0058-2755.1
Mid-American Energy Holdings Company	EPA-HQ-OAR-2002-0058-2786.1	Edison Electric Institute (EEI)	EPA-HQ-OAR-2002-0058-2755.1
Minnesota Power (ALLETE)	EPA-HQ-OAR-2002-0058-2829.1	Edison Electric Institute (EEI)	EPA-HQ-OAR-2002-0058-2755.1
Progress Energy	EPA-HQ-OAR-2002-0058-2868.1	Edison Electric Institute (EEI)	EPA-HQ-OAR-2002-0058-2755.1
Dominion Resources Services, Inc.	EPA-HQ-OAR-2002-0058-2908.1	Edison Electric Institute (EEI)	EPA-HQ-OAR-2002-0058-2755.1
Constellation Energy	EPA-HQ-OAR-2002-0058-3164	Edison Electric Institute (EEI)	EPA-HQ-OAR-2002-0058-2755.1
Wheelabrator Technologies	EPA-HQ-OAR-2002-0058-2812.1	Energy Recovery Council (ERC)	EPA-HQ-OAR-2002-0058-2831.1
City of Park Falls, WI	EPA-HQ-OAR-2002-0058-2350.1	Flambeau Rivers Paper, LLC	EPA-HQ-OAR-2002-0058-1839.1
United States Sugar Corporation	EPA-HQ-OAR-2002-0058-2853.1	Florida Sugar Industry	EPA-HQ-OAR-2002-0058-1841.1
Alexander & Baldwin, Inc (A&B)	EPA-HQ-OAR-2002-0058-3196.1	Florida Sugar Industry	EPA-HQ-OAR-2002-0058-1841.1
Packaging Corporation of America (PCA)	EPA-HQ-OAR-2002-0058-2385	Georgia Paper & Forest Products Association	EPA-HQ-OAR-2002-0058-2905

Table 3. Comments that reference other commentors, submitted to EPA-HQ-OAR-2002-0058

Comment	DCN Containing Reference	Comment Referenced or Incorporated by Reference	DCN of IBR letter
Tennessee Paper Council (TPC)	EPA-HQ-OAR-2002-0058-2691.1	Georgia Paper & Forest Products Association	EPA-HQ-OAR-2002-0058-2905
Georgia Industry Environmental Coalition (GEIC)	EPA-HQ-OAR-2002-0058-2882.1	Georgia Paper & Forest Products Association	EPA-HQ-OAR-2002-0058-2905
Packaging Corporation of America (PCA)	EPA-HQ-OAR-2002-0058-2913.1	Georgia Paper & Forest Products Association	EPA-HQ-OAR-2002-0058-2905
INVISTA S.à r.l.	EPA-HQ-OAR-2002-0058-2761.1	Georgia-Pacific	EPA-HQ-OAR-2002-0058-2745.1
USEC	EPA-HQ-OAR-2002-0058-3122	HOVENSA	EPA-HQ-OAR-2002-0058-2863.1
Celanese International Corporation	EPA-HQ-OAR-2002-0058-2840.1	Industrial Energy Consumers of America (IECA)	EPA-HQ-OAR-2002-0058-2752.1
PPG Industries, Inc.	EPA-HQ-OAR-2002-0058-2938.1	Industrial Energy Consumers of America (IECA)	EPA-HQ-OAR-2002-0058-2752.1
NewPage Corporation	EPA-HQ-OAR-2002-0058-2920.1	Industrial Energy Consumers of America (IECA)	EPA-HQ-OAR-2002-0058-2752.1
Dominion Resources Services, Inc.	EPA-HQ-OAR-2002-0058-2908.1	Interstate Natural Gas Association of America (INGAA)	EPA-HQ-OAR-2002-0058-2756.1
DTE Energy	EPA-HQ-OAR-2002-0058-2966.1	Interstate Natural Gas Association of America (INGAA)	EPA-HQ-OAR-2002-0058-2756.1
Citizens Thermal	EPA-HQ-OAR-2002-0058-2875.1	International District Energy Association (IDEA)	EPA-HQ-OAR-2002-0058-2918.1
State of New Hampshire Dept. of Environmental Services	EPA-HQ-OAR-2002-0058-2734.1	Maine DEP	EPA-HQ-OAR-2002-0058-2746.1
Energy Recovery Council (ERC)	EPA-HQ-OAR-2002-0058-2831.1	Maine DEP	EPA-HQ-OAR-2002-0058-2746.1
INVISTA S.à r.l.	EPA-HQ-OAR-2002-0058-2761.1	Manufacturers and Chemical Industry Council of North Carolina	EPA-HQ-OAR-2002-0058-2706.1
GDF SUEZ Energy Generation NA, Inc. (GSEGNA)	EPA-HQ-OAR-2002-0058-2946.1	Michigan Biomass	EPA-HQ-OAR-2002-0058-2776.1
Packaging Corporation of America (PCA)	EPA-HQ-OAR-2002-0058-2913.1	Michigan Forest Products Council (MFPC)	EPA-HQ-OAR-2002-0058-2744.1
Holland Board of Public Works (HBPW), Michigan	EPA-HQ-OAR-2002-0058-2907.1	Michigan Municipal Electric Association (MMEA)	EPA-HQ-OAR-2002-0058-2795.1
US Beet Sugar Association	EPA-HQ-OAR-2002-0058-2827.1	Company	EPA-HQ-OAR-2002-0058-2970.1
Minnesota Power (ALLETE)	EPA-HQ-OAR-2002-0058-2829.1	Minnesota Chamber of Commerce	EPA-HQ-OAR-2002-0058-2884.1
Iowa Department of Natural Resources (IDNR)	EPA-HQ-OAR-2002-0058-2767.1	National Association of Clean Air Agencies (NACAA)	EPA-HQ-OAR-2002-0058-2841.1
Weyerhaeuser	EPA-HQ-OAR-2002-0058-2797.1	National Alliance of Forest Owners (NAFO)	EPA-HQ-OAR-2002-0058-2750.1
Luminant	EPA-HQ-OAR-2002-0058-2780.1	National Association of Manufacturers (NAM)	EPA-HQ-OAR-2002-0058-2845.1
Tennessee Chamber of Commerce & Industry	EPA-HQ-OAR-2002-0058-2847.1	National Association of Manufacturers (NAM)	EPA-HQ-OAR-2002-0058-2845.1
Archer Daniels Midland Company (ADM)	EPA-HQ-OAR-2002-0058-2927.1	National Association of Manufacturers (NAM)	EPA-HQ-OAR-2002-0058-2845.1
West Virginia Manufacturers Association (WVMA)	EPA-HQ-OAR-2002-0058-2957.1	National Association of Manufacturers (NAM)	EPA-HQ-OAR-2002-0058-2845.1
ExxonMobil Refining and Supply Company	EPA-HQ-OAR-2002-0058-2968.1	National Association of Manufacturers (NAM)	EPA-HQ-OAR-2002-0058-2845.1
Council of Western State Foresters (CWSF)	EPA-HQ-OAR-2002-0058-2832.1	National Association of State Foresters (NASF)	EPA-HQ-OAR-2002-0058-2860.1
NewPage Corporation	EPA-HQ-OAR-2002-0058-2920.1	National Council of Air and Steam Improvement (NCASI)	EPA-HQ-OAR-2002-0058-2804.1
INVISTA S.à r.l.	EPA-HQ-OAR-2002-0058-2761.1	Project (NEDA/CAP)	EPA-HQ-OAR-2002-0058-2794.1
Weyerhaeuser	EPA-HQ-OAR-2002-0058-2797.1	Project (NEDA/CAP)	EPA-HQ-OAR-2002-0058-2794.1
Luminant	EPA-HQ-OAR-2002-0058-2780.1	National Mining Association	EPA-HQ-OAR-2002-0058-2787.1
Peabody Energy	EPA-HQ-OAR-2002-0058-2897.1	National Mining Association	EPA-HQ-OAR-2002-0058-2787.1
The Virginia Coal Association	EPA-HQ-OAR-2002-0058-2953.1	National Mining Association	EPA-HQ-OAR-2002-0058-2787.1
American Meat Institute (AMI)	EPA-HQ-OAR-2002-0058-2382.1	National Renderers Association	EPA-HQ-OAR-2002-0058-1868.1
Packaging Corporation of America (PCA)	EPA-HQ-OAR-2002-0058-2385	National Council of Air and Steam Improvement (NCASI)	EPA-HQ-OAR-2002-0058-2804.1
Tennessee Paper Council (TPC)	EPA-HQ-OAR-2002-0058-2691.1	National Council of Air and Steam Improvement (NCASI)	EPA-HQ-OAR-2002-0058-2804.1
P. H. Glatfelter Company	EPA-HQ-OAR-2002-0058-2694.1	National Council of Air and Steam Improvement (NCASI)	EPA-HQ-OAR-2002-0058-2804.1
Georgia-Pacific LLC	EPA-HQ-OAR-2002-0058-2745.1	National Council of Air and Steam Improvement (NCASI)	EPA-HQ-OAR-2002-0058-2804.1
International Paper	EPA-HQ-OAR-2002-0058-2777.1	National Council of Air and Steam Improvement (NCASI)	EPA-HQ-OAR-2002-0058-2804.1
Smurfit-Stone Container Corporation	EPA-HQ-OAR-2002-0058-2783.1	National Council of Air and Steam Improvement (NCASI)	EPA-HQ-OAR-2002-0058-2804.1
Weyerhaeuser	EPA-HQ-OAR-2002-0058-2797.1	National Council of Air and Steam Improvement (NCASI)	EPA-HQ-OAR-2002-0058-2804.1
Boise Inc.	EPA-HQ-OAR-2002-0058-2855.1	National Council of Air and Steam Improvement (NCASI)	EPA-HQ-OAR-2002-0058-2804.1
Georgia Paper & Forest Products Association (GPFPA)	EPA-HQ-OAR-2002-0058-2905	National Council of Air and Steam Improvement (NCASI)	EPA-HQ-OAR-2002-0058-2804.1
Packaging Corporation of America (PCA)	EPA-HQ-OAR-2002-0058-2913.1	National Council of Air and Steam Improvement (NCASI)	EPA-HQ-OAR-2002-0058-2804.1
South Carolina Pulp & Paper Association (SCPPA)	EPA-HQ-OAR-2002-0058-3154.1	National Council of Air and Steam Improvement (NCASI)	EPA-HQ-OAR-2002-0058-2804.1
Oilheat Manufacturers Association	EPA-HQ-OAR-2002-0058-3188	National Renderers Association	EPA-HQ-OAR-2002-0058-1868.1
USEC	EPA-HQ-OAR-2002-0058-3122	Nucor Steel	EPA-HQ-OAR-2002-0058-1732.1
Wisconsin Electric Power Company dba We Energies	EPA-HQ-OAR-2002-0058-2679.1	Southern Company	EPA-HQ-OAR-2002-0058-2741.1
FirstEnergy Generation Corp. (FGCO)	EPA-HQ-OAR-2002-0058-2772.1	Southern Company	EPA-HQ-OAR-2002-0058-2741.1
Dominion Resources Services, Inc.	EPA-HQ-OAR-2002-0058-2908.1	Southern Company	EPA-HQ-OAR-2002-0058-2741.1

Table 3. Comments that reference other commentors, submitted to EPA-HQ-OAR-2002-0058

Comment	DCN Containing Reference	Comment Referenced or Incorporated by Reference	DCN of IBR letter
Goodyear Tire & Rubber Company	EPA-HQ-OAR-2002-0058-3181	Rubber Manufacturers Association	EPA-HQ-OAR-2002-0058-2941.1
USEC	EPA-HQ-OAR-2002-0058-3122	Southern Company	EPA-HQ-OAR-2002-0058-2741.1
Tennessee Forestry Association	EPA-HQ-OAR-2002-0058-2603.1	Tennessee Paper Council	EPA-HQ-OAR-2002-0058-2691.1
Tennessee Chamber of Commerce & Industry	EPA-HQ-OAR-2002-0058-2847.1	Tennessee Paper Council	EPA-HQ-OAR-2002-0058-2691.1
Georgia Paper & Forest Products Association (GPFPA)	EPA-HQ-OAR-2002-0058-2905	Tennessee Paper Council	EPA-HQ-OAR-2002-0058-2691.1
Packaging Corporation of America (PCA)	EPA-HQ-OAR-2002-0058-2913.1	Tennessee Paper Council	EPA-HQ-OAR-2002-0058-2691.1
Weyerhaeuser	EPA-HQ-OAR-2002-0058-2797.1	TWC (Treated Wood Council)	EPA-HQ-OAR-2002-0058-2672.1
Ohio Chamber of Commerce	EPA-HQ-OAR-2002-0058-2901.1	US Chamber of Commerce	EPA-HQ-OAR-2002-0058-2799.1
Wisconsin Electric Power Company dba We Energies	EPA-HQ-OAR-2002-0058-2679.1	Utility Air Regulatory Group (UARG)	EPA-HQ-OAR-2002-0058-2880.1
American Electric Power (AEP)	EPA-HQ-OAR-2002-0058-2703.1	Utility Air Regulatory Group (UARG)	EPA-HQ-OAR-2002-0058-2880.1
Tucson Electric Power Co.	EPA-HQ-OAR-2002-0058-2726.1	Utility Air Regulatory Group (UARG)	EPA-HQ-OAR-2002-0058-2880.1
Southern Company	EPA-HQ-OAR-2002-0058-2741.1	Utility Air Regulatory Group (UARG)	EPA-HQ-OAR-2002-0058-2880.1
The Dayton Power of Light Company (DP and L)	EPA-HQ-OAR-2002-0058-2762.1	Utility Air Regulatory Group (UARG)	EPA-HQ-OAR-2002-0058-2880.1
Duke Energy	EPA-HQ-OAR-2002-0058-2765.1	Utility Air Regulatory Group (UARG)	EPA-HQ-OAR-2002-0058-2880.1
FirstEnergy Generation Corp. (FGCO)	EPA-HQ-OAR-2002-0058-2772.1	Utility Air Regulatory Group (UARG)	EPA-HQ-OAR-2002-0058-2880.1
Luminant	EPA-HQ-OAR-2002-0058-2780.1	Utility Air Regulatory Group (UARG)	EPA-HQ-OAR-2002-0058-2880.1
Ameren Corporation	EPA-HQ-OAR-2002-0058-2803.1	Utility Air Regulatory Group (UARG)	EPA-HQ-OAR-2002-0058-2880.1
Manitowoc Public Utilities	EPA-HQ-OAR-2002-0058-2810.1	Utility Air Regulatory Group (UARG)	EPA-HQ-OAR-2002-0058-2880.1
Minnesota Power (ALLETE)	EPA-HQ-OAR-2002-0058-2829.1	Utility Air Regulatory Group (UARG)	EPA-HQ-OAR-2002-0058-2880.1
National Rural Electric Cooperative Association (NRECA)	EPA-HQ-OAR-2002-0058-2835.1	Utility Air Regulatory Group (UARG)	EPA-HQ-OAR-2002-0058-2880.1
Progress Energy	EPA-HQ-OAR-2002-0058-2868.1	Utility Air Regulatory Group (UARG)	EPA-HQ-OAR-2002-0058-2880.1
Consumers Energy	EPA-HQ-OAR-2002-0058-2904.1	Utility Air Regulatory Group (UARG)	EPA-HQ-OAR-2002-0058-2880.1
Dominion Resources Services, Inc.	EPA-HQ-OAR-2002-0058-2908.1	Utility Air Regulatory Group (UARG)	EPA-HQ-OAR-2002-0058-2880.1
Tennessee Valley Authority (TVA)	EPA-HQ-OAR-2002-0058-2963.1	Utility Air Regulatory Group (UARG)	EPA-HQ-OAR-2002-0058-2880.1
DTE Energy	EPA-HQ-OAR-2002-0058-2966.1	Utility Air Regulatory Group (UARG)	EPA-HQ-OAR-2002-0058-2880.1
Constellation Energy	EPA-HQ-OAR-2002-0058-3164	Utility Air Regulatory Group (UARG)	EPA-HQ-OAR-2002-0058-2880.1
Iowa Department of Natural Resources (IDNR)	EPA-HQ-OAR-2002-0058-2767.1	Wisconsin Department of Environmental Quality	EPA-HQ-OAR-2002-0058-2853.1
USEC	EPA-HQ-OAR-2002-0058-3122	Wisconsin Electric Power Company dba We Energies	EPA-HQ-OAR-2002-0058-2679.1
Quad/Graphics, Inc.	EPA-HQ-OAR-2002-0058-2898.1	Wisconsin Paper Council	EPA-HQ-OAR-2002-0058-2773.1
Georgia Paper & Forest Products Association (GPFPA)	EPA-HQ-OAR-2002-0058-2905	Wisconsin Paper Council	EPA-HQ-OAR-2002-0058-2773.1
Packaging Corporation of America (PCA)	EPA-HQ-OAR-2002-0058-2913.1	Wisconsin Paper Council	EPA-HQ-OAR-2002-0058-2773.1