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Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments

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Subpart C -- General Stationary Fuel Combustion Sources

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Subpart C -- General Stationary Fuel Combustion Sources

U. S. Environmental Protection Agency
Office of Atmosphere Programs
Climate Change Division
Washington, D.C.

FOREWORD

This document provides EPA's responses to public comments on EPA's Proposed Mandatory Greenhouse Gas Reporting Rule. EPA published a Notice of Proposed Rulemaking in the Federal Register on April 10, 2009 (74 FR 16448). EPA received comments on this proposed rule via mail, e-mail, facsimile, and at two public hearings held in Washington, DC and Sacramento, California in April 2009. Copies of all comments submitted are available at the EPA Docket Center Public Reading Room. Comments letters and transcripts of the public hearings are also available electronically through http://www.regulations.gov by searching Docket ID *EPA-HQ-OAR-2008-0508.*

Due to the size and scope of this rulemaking, EPA prepared this document in multiple volumes, with each volume focusing on a different broad subject area of the rule. This volume of the document provides EPA's responses to the significant public comments received for 40 CFR Part 98, Subpart C -- General Stationary Fuel Combustion Sources.

Each volume provides the verbatim text of comments 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. 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 table(s) at the end of each volume (as appropriate).

EPA's responses to comments are generally 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.

While every effort was made to include the significant comments related to 40 CFR Part 98, Subpart C -- General Stationary Fuel Combustion Sources in this volume, some comments inevitably overlap multiple subject areas. For comments that overlapped two or more subject areas, EPA assigned the comment to a single subject category based on an assessment of the principle subject of the comment. For this reason, EPA encourages the public to read the other volumes of this document with subject areas that may be relevant to 40 CFR Part 98, Subpart C -- General Stationary Fuel Combustion Sources.

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Commenter Name: Karen St. John
Commenter Affiliation: BP America Inc. (BP)
Document Control Number: EPA-HQ-OAR-2008-0508-0631.1
Comment Excerpt Number: 34

Comment: Continuous Emissions Monitoring System §98.6 (p. 16618): EPA's definition of CEMS includes a requirement for "readings every 15 minutes" which is not appropriate for a definition.

Response: See the Preamble and separate comment response document volumes for the response on the general monitoring approach and general recordkeeping requirements.

The commenter does not claim that the frequency of readings by equipment qualifying as a CEMS should be different than at least once every 15 minutes, but rather claims that a requirement for readings every 15 minutes is "not appropriate" to include in a definition. EPA rejects this comment because it is certainly reasonable to include, in the definition of a term (CEMS) that, on its face, includes the concept of "continuous" monitoring, a performance specification concerning frequency of monitored readings. Moreover, this performance specification has been used in defining "CEMS" in the Acid Rain Program since the program began in 1995 and, in conjunction with other elements of the monitoring requirements in that program, has resulted in a high level of data quality and consistency.

Commenter Name: Randall R. LaBauve
Commenter Affiliation: Florida Power & Light (FPL) Group
Document Control Number: EPA-HQ-OAR-2008-0508-0624.1
Comment Excerpt Number: 12

Comment: Proposed §§98.30 and 98.40 would exempt portable equipment and emergency generators from GHG emission reporting requirements. Due to the minimal GHG emissions expected from such equipment, FPL Group supports the equipment's exemption from the proposed reporting requirements. However, we believe that EPA has crafted the proposed exemption too narrowly. Under proposed §§98.30 and 98.40, only portable equipment and emergency generators that are designated as emergency generators in a permit issued by a state or local air pollution control agency would be exempt from the reporting requirements of the regulation. FPL Group believes that the permit designation restriction is unnecessary. Because GHG emissions from such equipment are generally minimal, and because exempt emergency generators would already be required to meet the specifications listed in the definition of "emergency generators" under proposed §98.6, there is no reason to add a further restriction that the equipment be listed in a permit. Some states exempt emergency generators from construction or operating permits if certain operating criteria are met. For example, in Wisconsin an emergency electric generator means "an electric generator whose purpose is to provide electricity to a facility if normal electrical service is interrupted and which is operated no more than 200 hours per year." Wis. ADMIN. CODE NR 400.02(56). An emergency electrical generator fitting this definition is exempt from construction or operating permit requirements provided it is "powered by internal combustion engines which are fueled by gaseous fuels, gasoline or distillate fuel oil with an electric output of less than 3,000 kilowatts." Wis. ADMIN. CODE NR 406.04(1)(w) and 407.03(1)(u)). As a result of such state exemptions, emergency generators may be designated as emergency generators by the state, but not included in the state or local air pollution control agency permit. For these reasons, FPL Group believes that proposed §§98.30 and 98.40 should be revised to simply state that portable equipment and emergency generators that meet the definition of "emergency generators" under §98.6 are excluded from the proposed reporting requirements of applicable source categories. At a minimum, EPA should expand the exemption to apply not only to emergency generators that are exempted by permit but also to emergency generators that are exempted from permitting.

Response: EPA has maintained the exclusion of emergency generators, and has excluded other emergency equipment from reporting. EPA has also revised the rule language to exclude the prerequisite for a state or local permit. Please refer to the full definitions of emergency generator and emergency equipment in §98.6.

Commenter Name: Edward N. Saccoccia
Commenter Affiliation: Praxair Inc.
Document Control Number: EPA-HQ-OAR-2008-0508-0977.1
Comment Excerpt Number: 1

Comment: The proposed rule appropriately excludes minor combustion sources from the definition of the Stationary Fuel Combustion source category, in particular process safety flares. Praxair supports this effort to minimize the burden on regulated facilities, as these units typically have very low emissions, typically do not have measured flow rates, and do not make a substantial impact on the total greenhouse gas inventory. Where flaring operations are a routine operating control of a facility, such as in refineries, EPA has explicitly included emission estimation and reporting requirements. Clarify that flare emissions should only be included in the calculations of Subpart C of the rule if another subpart of the rule explicitly requires such emission calculation and reporting. Flare emissions should be otherwise excluded categorically or as a de minimis source.

Response: EPA has revised the language of the final rule to expand the list of exempted source categories to include flares as defined in §98.6, except where required to report by provisions of another subpart of Part 98 (see §98.30(b)).

Commenter Name: See Table 5
Commenter Affiliation:
Document Control Number: EPA-HQ-OAR-2008-0508-0480.1
Comment Excerpt Number: 41

Comment: Section §98.30(b) excludes emergency generators from the Subpart C source category. However, §98.30(b) indicates that the generators need to be designated as emergency generators in a permit issued by a state or local air pollution control agency. The permitting requirement should be removed from this provision. Requirements differ for different jurisdictions. For example, units with a rating below a certain size may not be included in a permit. Thus, the small emergency units that EPA is attempting to exempt are exactly the type that is most likely to not be in a permit, because states are more likely to not require permits for small units. Section §98.30(b) should simply exempt portable and emergency units and delete the qualifying phrase related to permitting. Additional clarification on engine classification may be warranted, but the permit requirement must be deleted from the rule to avoid applicability for many small, emergency engines.

Response: EPA has maintained the exclusion of emergency generators, and has excluded other emergency equipment from reporting. Without further elucidation of what clarification on engine classication is sought, EPA is unable to respond to such a general comment. EPA has also revised the rule language to exclude the prerequisite for a state or local permit. Please refer to the full definitions of emergency generator and emergency equipment in §98.6.

Commenter Name: Rich Raiders
Commenter Affiliation: Arkema Inc.
Document Control Number: EPA-HQ-OAR-2008-0508-0511.1
Comment Excerpt Number: 40

Comment: Some facilities using liquid or solid fuels only track fuel usage on an as-delivered basis. These facilities collect fuel data upon receipt of each shipment of fuel oil or coal, and assume that all purchased fuel is consumed in the year of purchase. This step occurs because these facilities, some of whom will likely become subject to Part 98, have not needed to install accurate liquid or solid fuel measurement systems. Also, operators of emergency generators sometimes track fuel usage as a function of run time, where the fuel usage is estimated by the total run time multiplied by the maximum hourly rated fuel usage. EPA should authorize this approach for emergency generators, portable temporary generators used for short time periods at a facility, and smaller internal combustion engines not equipped with Subpart C fuel measurement systems. Many of these systems are used by a facility during maintenance events, emergencies, or other short-term purposes, and are shipped as packaged units without the customer/report being able to modify the system. If EPA does not exempt emergency generators or small internal combustion engines from reporting, EPA should allow these standard emission estimation methods to be used for portable generators or similar units. Also, EPA should defer to the September 6, 1995 emergency generator guidance describing EPA's approach to emergency generator use. http://www.epa.gov/ttn/oarpg/t5/memoranda/emgen.pdf EPA's policy, which can be adjusted by the local permitting authorities as required, recommended 500 hours per year as an appropriate threshold for the appropriate operating time for emergency generators. Part 98 should not seek to overturn this memo, where the permitting authorities have made a series of decisions based on this historic EPA decision. EPA should presumptively exempt emergency generators properly authorized by the appropriate permitting authority from this reporting rule.

Response: See the Preamble, Section II. K., and response to comment EPA-HQ-OAR-2008-0508-0423.2 excerpt 40 for the response on de minimis reporting for small emission points.

EPA has maintained the exclusion of emergency generators, has excluded other emergency equipment, as defined in §98.6, and has revised the language to remove the prerequisite for a state or local permit. Portable equipment, as defined in §98.6, is also exempt from reporting. Other small stationary combustion sources may use the calculation methods provided in Tier 1 or Tier 2, and stationary combustion sources using homogenous fuels like natural gas and diesel oil may use Tier 2. Both of these tiers allow facilities to determine fuel use based on company records, and do not require the direct measurement of fuel flow.

Commenter Name: Rich Raiders
Commenter Affiliation: Arkema Inc.
Document Control Number: EPA-HQ-OAR-2008-0508-0511.1
Comment Excerpt Number: 39

Comment: EPA should explicitly state that facilities do not need to report fuel use for comfort heating and hot water heater (for personal use) purposes. Some facilities may not have accurate flow meters measuring domestic hot water heaters and comfort heaters, and compliance with the Subpart C provisions are not appropriate for these types of units. Smaller facilities should also have the option of using site-wide gas consumption meters in lieu of individual commodity fuel metering.

Response: See the Preamble and separate comment response document volume for the response on monitoring and QA/QC requirements, and de minimis reporting for small emission points.

In preparation of the final rule, EPA has revised many sections of the rule that may be relevant to this comment. First, in order to reduce the burden of compliance, EPA has explicitly allowed for the use of company records to determine fuel consumption. EPA has also removed the cumulative 250 mmBtu/hr restriction on unit aggregation, and has clarified the common pipe reporting option. In §98.30, EPA has expanded the list of sources excluded from coverage; however, this expansion does not include comfort heating and hot water (for personal use) purposes, and as such, these activities would be included under Subpart C for facilities that are required to comply with Part 98.

Commenter Name: Michael DiMauro
Commenter Affiliation: Massachusetts Municipal Wholesale Electric Company (MMWEC)
Document Control Number: EPA-HQ-OAR-2008-0508-0580
Comment Excerpt Number: 4

Comment: EPA should re-consider its decision to not exempt small and/or low utilization stationary combustion units from GHG Reporting. Rather it is proposed that a DeMinimus category be established that would include combustion units with a design heat input < 20-5 0 MMBtu/hr and/or units that have limited utilization (e.g. < 25%). Alternatively this Deminimus category could be defined by a CO_2 emission restriction of perhaps 100 tons/year, to be demonstrated by simple estimation methods. Units satisfying these Deminimus criteria would be exempt from GHG Reporting.

Response: See the Preamble and separate comment response document volume for the response on de minimis reporting for small emission points.

EPA has expanded the list of exempted source categories to include portable equipment, emergency generators, other emergency equipment, irrigation well devices, and flares. EPA has also removed the cumulative 250 mmBtu/hr restriction on unit aggregation and clarified the use of the common pipe alternative reporting provision, and believes that the expanded availability of these options, which would allow site-wide gas consumption meters, will reduce the reporting burden on facilities.

Commenter Name: Karen St. John
Commenter Affiliation: BP America Inc. (BP)
Document Control Number: EPA-HQ-OAR-2008-0508-0631.1
Comment Excerpt Number: 37

Comment: Emergency generator §98.6 (p. 16620): The definition of 'Emergency generator' states "the hours of operation per calendar year for performance testing shall not exceed 100 hours." BP requests that the specification of hours be removed from the definition of emergency generators. It is not reasonable to limit the number of hours.

Response: EPA has maintained the exclusion of emergency generators, and has excluded other emergency equipment from reporting. The final rule eliminates the 100 hour limitation for emergency generators. Please refer to the full definitions of emergency generator and emergency equipment in §98.6. ""

Commenter Name: Sarah E. Amick
Commenter Affiliation: The Rubber Manufacturers Association (RMA)
Document Control Number: EPA-HQ-OAR-2008-0508-0647.1
Comment Excerpt Number: 4

Comment: RMA opposes the requirement that facilities report electricity generated from portable and emergency generators. Portable and emergency generators are operated during a limited time per year. In fact, EPA's proposed National Emissions Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines (RICE MACT) would reduce the regulatory burden based on the limited operation of these emergency generators to 100 hours per year. (74 Fed. Reg. 9698). Requiring data regarding electricity generated from these types of engines is burdensome and creates no environmental benefit.

Response: EPA agrees with the commenter, and the final rule maintains the exclusion of emergency generators, eliminates the 100-hour limitation for emergency generators, has excluded other emergency equipment, as defined in §98.6, and has revised the rule language to remove the prerequisite for a state or local permit. Portable equipment, as defined in §98.6, is also exempt from reporting. This exemption applies to both Subpart C and Subpart D.

Commenter Name: See Table 5
Commenter Affiliation:
Document Control Number: EPA-HQ-OAR-2008-0508-0480.1
Comment Excerpt Number: 34

Comment: INGAA supports the aggregation approaches for unit-level reporting identified in §98.36(c). §98.36(c)(1) allows aggregate reporting for up to 250 MMBtu/hr of combustion sources at a facility and §98.36(c)(3) allows multiple gas-fired or oil-fired units fed through a common fuel line to report insignificant affect on facility emissions. Affected sources are faced with significant implementation challenges due to the breadth and timing of the Proposed Rule, and the additional burden associated with reporting trivial emissions is not warranted. INGAA recommends that a 10 MMBtu/hr exemption threshold be included in the rule for combustion sources.

Response: See the Preamble and separate comment response document volume for the response on de minimis reporting for small emission points.

EPA appreciates the commenter's support of the reporting alternatives provided in §98.36(c). The final rule includes further clarification and flexibility regarding aggregation and common pipe provisions that will reduce the burden on sources. First, in order to reduce the burden of compliance, EPA has explicitly allowed for the use of company records to determine fuel consumption. EPA has also removed the cumulative 250 mmBtu/hr restriction on unit aggregation, and has clarified the common pipe reporting option. In §98.30, EPA has expanded the list of sources excluded from coverage. These sources would be included under Subpart C for facilities that are required to comply with Part 98.

Commenter Name: Fiji George
Commenter Affiliation: El Paso Corporation
Document Control Number: EPA-HQ-OAR-2008-0508-0398.1
Comment Excerpt Number: 33

Comment: Addressing flares in Subpart C would ensure consistent treatment of this equipment in each industry segment and would be a step toward streamlining the regulation.

Response: EPA has revised the language of the final rule to exclude flares as defined in §98.6 from reporting under Subpart C, except where required to report by provisions of another subpart of Part 98 (see §98.30(b)). EPA believes that this revised language is appropriate because it will require emissions to be reported for major flare sources (such as refinery flares), while sparing the expense of reporting emissions for small miscellaneous flare sources.

Commenter Name: Patrick J. Nugent
Commenter Affiliation: Texas Pipeline Association (TPA)
Document Control Number: EPA-HQ-OAR-2008-0508-0460.1
Comment Excerpt Number: 25

Comment: TPA recommends the use of two separate thresholds. TPA supports the inclusion of a MMBtu/hr threshold for combustion sources, but we recommend that there be two such thresholds: (1) a 50 MMBtu/hr threshold for sources combusting natural gas only, and (2) the 30 MMBtu/hr threshold for all other combustion sources. The proposed 30 MMBtu/hr threshold is evidently based on the combustion of utility coal based on data from a July 7, 2008 memorandum from Leif Hockstad on "Maximum rated heat input capacity compared to 25,000 $MMTCO_2e$ threshold." See docket item EPA-HQ-OAR-2008-0508-0049. Using the same data from that memorandum for natural gas combustion, a 50 MMBtu/hr threshold would equate to 23,240 $MMTCO_2e$, which is less than the 25,000 threshold.

Response: See the Preamble and separate comment response document volume for the response on selection of the threshold See the Preamble, Section II. E., and response to comment EPA-HQ-OAR-2008-0508-0350.1 excerpt 3 for additional explanation of the selection and form of thresholds..

EPA acknowledges the concerns of the commenter, but will continue to use the 25,000 metric ton CO_2e threshold for facilities that only include stationary combustion equipment. The 30 mmBtu/hr provision, as described in §98.2(a)(3)(ii) of the general provisions, is not a separate threshold, but was given to provided guidance to smaller facilities that might not be subject to applicability determinations.

Commenter Name: Ron Downey
Commenter Affiliation: LWB Refractories
Document Control Number: EPA-HQ-OAR-2008-0508-0719.1
Comment Excerpt Number: 25

Comment: 40 C.F.R. 98.33 and Table C-1 require sources to include biomass fuel emissions in the emissions calculation for stationary fuel combustion sources. LWB believes that biomass should be excluded from the emissions calculation for stationary fuel combustion sources because biomass offsets carbon emission from fossil fuel combustion and is also considered carbon neutral. See link: http://www.eia.doe.gov/oiaf/1605/coefficients.html. NLA proposes that biomass (which does not encompass municipal solid waste) be excluded from the emissions calculation for stationary fuel combustion sources because use of biomass fuel reduces GHG emissions and biomass emissions are not included in determining whether a source meets the emissions threshold. 40 C.F.R 98.33.

Response: See the response to comment EPA-HQ-OAR-2008-0508-0690.1 excerpt 1 corresponding to Section II. of the Preamble, and the response to comment EPA-HQ-OAR-2008-0508-0631.1 excerpt 71 corresponding to Subpart C for additional explanation of the reporting of biogenic CO_2 emissions.

While EPA has decided to track biogenic emissions separately, they still must be included in the total CO_2 emissions reported. EPA believes that it is clear in the revised §98.2 that CO_2 emissions from biogenic fuels do not count toward the 25,000 metric ton threshold for reporting for stationary combustion units, although CH_4 and N_2O emissions from biogenic fuels must be considered. In this rule, EPA does not assess carbon neutrality or offsets.

Commenter Name: Sam Chamberlain
Commenter Affiliation: Murphy Oil Corporation
Document Control Number: EPA-HQ-OAR-2008-0508-0625
Comment Excerpt Number: 25

Comment: "EPA is proposing to not require reporting of emissions from portable equipment or generating units designated as emergency generators in a permit issued by a state or local air pollution control agency. We request comment on whether or not a permit should be required for these emergency generators." (Preamble, p. 174) The exclusion should be not just for permitted emergency generators, but for non-permitted emergency equipment (such as fixed firewater pumps or non-permitted emergency generators). During Murphy turnarounds, or emergency situations after hurricanes along the Texas/Louisiana Gulf Coast, there is a priority need to get these generators on line as soon as possible in order to provide for the safety and well-being of the citizens of the USA. In these crisis situations, getting fuel supplies to the consumer is critical. Taking the time, energy, effort and resources to determine if specific generators are permitted or not, seems to be an overzealous action that removes the protection and welfare of our citizens, while trying to respond to an emergency. EPA should not require the reporting of emergency generators under any circumstances.
Response: EPA has maintained the exclusion of emergency generators, and has excluded other emergency equipment from reporting. EPA has also revised the rule language to remove the prerequisite for a state or local permit. Please refer to the full definitions of emergency generator and emergency equipment in §98.6.

Commenter Name: See Table 7
Commenter Affiliation:
Document Control Number: EPA-HQ-OAR-2008-0508-0412.1
Comment Excerpt Number: 24

Comment: GPA opposes requiring the reporting of GHG emissions from temporary or portable equipment. Temporary or portable equipment is generally used for such limited periods during the year that the burden of monitoring, recordkeeping and reporting data from temporary or portable equipment is disproportionate to the value of the data collected.

Response: EPA agrees with the commenter, and has exempted from reporting portable equipment, as defined in §98.6 in the final rule language.

Commenter Name: Fiji George
Commenter Affiliation: El Paso Corporation
Document Control Number: EPA-HQ-OAR-2008-0508-0398.1
Comment Excerpt Number: 38

Comment: El Paso supports the exclusion of emissions associated with emergency generators, portable and temporary emissions units as defined under §98.6 from the proposed emissions requirements under §98.30. However, the exclusion should be expanded beyond equipment designated as emergency in air permits issued by state or local air pollution control agencies. It should be noted that some emergency equipment may not require air permitting. It would take considerable amount of effort and time from the regulated facilities and air pollution control agencies to modify existing air permits to include these small units. El Paso recommends that the exclusion be expanded to include any units represented as emergency units in the air permit applications or correspondence to air pollution control agencies providing that these units are operated as emergency units and the companies maintain adequate operating records to prove emergency status of these units. The level of effort undertaken to document these emissions if it were to be reported is unwarranted.

Response: EPA has maintained the exclusion of emergency generators, and has excluded other emergency equipment from reporting. EPA has also revised the rule language to remove the prerequisite for a state or local permit. Please refer to the full definitions of emergency generator and emergency equipment in §98.6.

Commenter Name: Jack Gehring et al.
Commenter Affiliation: Caterpillar Inc.
Document Control Number: EPA-HQ-OAR-2008-0508-0499.1
Comment Excerpt Number: 8

Comment: Caterpillar supports EPA's proposal (Section V (C), "General Stationary Combustion Sources") to not require reporting of GHG emissions from already-permitted (by state/local authorities) portable equipment or generating units designated as emergency generators, but requests that EPA broaden the scope of this exemption to include manufacturers' families of such emergency engines. Existing EPA regulations (the NSPS for Stationary Combustion-Ignition Engines) already required emergency engine certification when Tier 4 begins. Use of these engines will be limited by the NSPS to emergency service and associated testing only, and have specific emissions limits and unique labeling requirements. Because of the certification requirements, specific emissions limits and use restrictions in existing EPA regulations, Caterpillar requests that eligibility for this EPA exemption not depend upon state/local authority permit coverage, especially since the exemption thresholds in non-major source state permitting schemes vary widely, and eligibility for the exemption would be difficult for both manufacturers and customers to determine. Accordingly, Caterpillar requests that EPA broaden the scope of this exemption to include manufacturers' families of affected emergency engines. At minimum, however, EPA should retain the proposed exemptions for engines permitted by state/local authorities.

Response: EPA has maintained the exclusion of emergency generators, and has excluded other emergency equipment from reporting. EPA has also revised the rule language to remove the

prerequisite for a state or local permit. Please refer to the full definitions of emergency generator and emergency equipment in §98.6.

Commenter Name: Anonymous
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2008-0508-0166
Comment Excerpt Number: 6

Comment: Consider excluding all diesel generators if they operate under a 500 hour per year threshold, regardless if whether they are classified as "emergency only" gensets. Note the 500 hour limit is based on EPA guidance for PTE on emergency generators.

Response: See the Preamble for the response on de minimis reporting for small emission points, which includes a discussion on small combustion devices that are not emergency generators.

Because of the need for comprehensive, national greenhouse gas emissions data, the final rule provides only limited exclusions from the reporting requirements. In light of this need for comprehensive data, EPA has instead taken the approach of limiting the exclusions but allowing reporting methods that provide data of a sufficient level of quality and consistency for the purposes of this rule but that reduce the reporting burden on reporters. For example, in the final rule, EPA has maintained the exclusion of emergency generators, has removed for such generators the 100-hour limitation and the requirement of designation in a state or local permit, and has excluded other emergency equipment from reporting. See §98.6, which includes definitions of emergency generator and emergency equipment. Diesel generators that operate under 500 hours per year are not necessarily for emergency use only but may operate for other purposes, and, particularly since the generators can be of widely varying sizes, the GHG emissions from these generators cannot be assumed to be, and treated as, insignificant. While this category of sources is, for the above-discussed reasons, not excluded from reporting, the final rule allows the use of an aggregation of units method found in §98.36(c)(1) for reporting multiple combustion devices individually rated at 250 mmBtu/hr or less that reduces the burden to the reporter in accounting for small combustion devices that are not emergency generators. Other small stationary combustion sources may use the calculation methods provided in Tier 1 or Tier 2 in the rule. In particular, stationary combustion sources using homogenous fuels like natural gas and diesel oil may use the calculation methods provided in Tier 2.

Commenter Name: Andrew C. Lawrence
Commenter Affiliation: Department of Energy (DOE)
Document Control Number: EPA-HQ-OAR-2008-0508-0612.1
Comment Excerpt Number: 12

Comment: Many complex facilities subject to the reporting rule under §98.2(a)(1), (a)(2), or (a)(3) will be required to inventory a large number of small combustion units covered by the rule. DOE believes a size threshold is needed in the stationary combustion source category to reduce undue cost burden while still achieving the goal of obtaining GHG data of sufficient quality that it can be used to support a range of future climate change policies and regulations. DOE recommends that the source definition in Subpart C be aligned to match the intent of the rule to focus on large emitters and to clarify the sources subject to the rule. In particular, this should include definitions for commercial and residential fuel combustion sources; exclude residential units from the source category; and set a capacity threshold for commercial-size units, such as 10 million British Thermal Units, (the current exemption from the Boiler maximum achievable control technology (MACT) and for many state Title V programs), that are excluded from the source.

Response: See the Preamble for the response on de minimis reporting for small emission points.

EPA agrees that residential sources should not be included in the category of stationary fuel combustion sources and notes that §98.30 does not include residential sources. That section states that stationary fuel combustion sources are "devices that combust solid, liquid, or gaseous fuel, generally for the purposes of producing electricity, generating steam, or providing useful heat or energy for <u>industrial, commercial, or institutional use</u>, or reducing the volume of waste by removing combustible matter" (emphasis added).

EPA does not agree that a size threshold for reporting for commercial sources is warranted. Because of the need for comprehensive, national greenhouse gas emissions data, the final rule provides only limited exclusions from the reporting requirements. In light of this need for comprehensive data, EPA has instead taken the approach of limiting the exclusions but allowing reporting methods that provide data of a sufficient level of quality and consistency for the purposes of this rule but that reduce the reporting burden on reporters. For example, EPA has excluded from the reporting requirements emergency generators and other emergency equipment, but has not adopted a 10 mmBtu/hr capacity threshold for commercial units. Such commercial units may be routinely used, and so the GHG emissions from these units cannot be assumed to be, and treated as, insignificant. While this category of sources is, for the reasons discussed above, not excluded from reporting, the final rule removes the cumulative 250 mmBtu/hr restriction on unit aggregation and clarifies the common pipe reporting option. The rule also explicitly allows for the use of company records to determine fuel consumption.

Commenter Name: Kelly R. Carmichael
Commenter Affiliation: NiSource
Document Control Number: EPA-HQ-OAR-2008-0508-1080.2
Comment Excerpt Number: 11

Comment: NiSource agrees with EPA for proposing to not require reporting of GHG emissions from portable equipments and generating units designated as emergency generators. However, EPA should eliminate the state and local permit requirement attached to this exemption. Requirements differ for different jurisdictions. Based on the experience of NiSource operating in more than 10 states, the state permit requirements vary considerably within our operations. The definition of emergency generator also varies in air pollution control programs from state to state. NiSource requests that EPA should clarify that portable equipments and emergency generators are exempt from every source category, including electricity generation.

Response: EPA has revised the rule language to remove the requirement for a state or local permit to be attached to the exemption for portable or emergency generating equipment. Please refer to the full definitions of emergency generator and emergency equipment in §98.6. This exemption applies to the electricity generation source category, as well as the general stationary combustion source category.

Commenter Name: Sarah E. Amick
Commenter Affiliation: The Rubber Manufacturers Association (RMA)
Document Control Number: EPA-HQ-OAR-2008-0508-0647.1
Comment Excerpt Number: 10

Comment: Subpart C of the proposed rule excludes emissions reporting from portable equipment or generating units designated as emergency generators in a permit issued by a state or local air pollution control agency. EPA requested comment on whether or not a permit should be required for these emergency generators (74 Fed. Reg. at 16480). RMA believes this requirement is too restrictive. Many tire industry facilities have pumps that are integral components of facility fire suppression systems. The pumps are often driven by diesel-fired internal combustion engines. These engines would typically meet the proposed definition of emergency generators. However, since they are considered emergency equipment, they are often excluded from state and local air permit requirements. In fact, typically, these engines need not even be included in air permit applications. Furthermore, when such equipment is included in an air permit it is unlikely to be designated specifically as an "emergency generator." Thus, the proposed requirement that such equipment be designated as emergency generators in an air permit, would fail to exclude the majority of such equipment. Therefore, RMA recommends that the proposed requirement be revised to exclude emissions reporting from portable equipment or generating units that operate in compliance with state or local air pollution control agency requirements.

Response: EPA has revised the rule language to remove the prerequisite for a state or local permit for emergency generators. Please refer to the full definitions of emergency generator and emergency equipment in §98.6.

Commenter Name: Chris Hornback
Commenter Affiliation: National Association of Clean Water Agencies (NACWA)
Document Control Number: EPA-HQ-OAR-2008-0508-0566.1
Comment Excerpt Number: 10

Comment: Additional clarification is needed on the scope of the combustion units that must be included. Are units that are currently considered insignificant activities under Title V required to be included? For example, are small boilers or furnaces using natural gas to heat office space required to be included when calculating total facility emissions for comparison against the threshold?

Response: See the Preamble for the response on de minimis reporting for small emission points.

EPA has revised the final rule to clarify the definition of the stationary combustion source category. EPA intends that this source category will capture combustion sources that are not associated with another source category as defined in the rule. The commenter should consider §98.2(a)(3) about whether the facility needs to report under the rule, and §98.30 in order to determine whether specific units should be included in emissions calculations.

Commenter Name: Verne Shortell
Commenter Affiliation: NRG Energy, Inc.
Document Control Number: EPA-HQ-OAR-2008-0508-0634.1
Comment Excerpt Number: 2

Comment: This section can be read to mean that only portable equipment and emergency generators that are included in a site permit (NSR, PSD, Title V) are exempt from the reporting requirements of the regulation. Since GHG emissions from such equipment should be minimal and emergency generators are only exempt from reporting if they meet the specifications listed in the definition (§98.6; page 16620), there is no reason to add a further requirement that the equipment be listed in a permit. This section should be revised to state that portable equipment and emergency generators meeting the definition in Section 98.6 are exempt from the GHG reporting requirements.

Response: EPA has maintained the exclusion of emergency generators, and has excluded other emergency equipment from reporting. EPA has also revised the rule language to remove the prerequisite for a state or local permit. Please refer to the full definitions of emergency generator and emergency equipment in §98.6. Portable equipment, as defined in §98.6, is also exempt from reporting.

Commenter Name: Kelly R. Carmichael
Commenter Affiliation: NiSource
Document Control Number: EPA-HQ-OAR-2008-0508-1080.2
Comment Excerpt Number: 9

Comment: After review of Part 98.30, it appears that a "combustion source" and a "device" are synonymous, but then there is no further clarification. EPA needs to explain the difference between a "combustion source" and a "device."

Response: In response to the comments, EPA does not believe that any additional language is needed to address the differences between the terms "combustion source," "combustion unit," and "device," as they are used in Subpart C. As stated in §98.30 of the final rule, "Stationary fuel combustion sources are devices that combust solid, liquid, or gaseous fuel, generally for the purposes of producing electricity, generating steam, or providing useful heat or energy for industrial, commercial, or institutional use, or reducing the volume of waste by removing combustible matter." The use of the word "device" is not limited in any way by the definition of the source category, general stationary fuel combustion. "Source" refers to those devices that do meet the provisions of the definition of the source category, as presented in §98.30. "Unit" generally describes a device that could be subject to the reporting requirements (were it to meet the specifications listed in §98.30).

Commenter Name: Thomas Siegrist
Commenter Affiliation: Koch Nitrogen Company LLC
Document Control Number: EPA-HQ-OAR-2008-0508-0351.1
Comment Excerpt Number: 16

Comment: The Proposed Rule would not require reporting of emissions from portable equipment or generating units designated as emergency generators in a permit issued by a state or local air pollution control agency (proposed §98.30(b)). KNC strongly agrees that reporting of GHG emissions from such sources would not significantly improve the accuracy of a GHG emissions inventory; however the proposed requirement that such units must be included in a state or local air permit in order for their emissions to be excluded is not warranted. If inclusion of the entire class of such sources would not significantly affect the accuracy of an emissions inventory, inclusion of a sub-set of that class would be even less meaningful. Moreover, many air permitting agencies simply exempt emergency generators from permitting requirements, and EPA has approved such permitting exemptions in numerous state implementation plans. As written, the Proposed Rule would require reporting for all emergency generators located in those states, creating disparate reporting on similarly situated equipment in different states. For these reasons, EPA should revise the proposed exclusion to include not only equipment designated in an air permit but also all portable equipment and all equipment used in emergency service that is exempt from air permit requirements by the rules of the applicable state or local air pollution control agency.

Response: EPA has maintained the exclusion of emergency generators, and has excluded other emergency equipment from reporting. EPA has also revised the rule language to remove the prerequisite for a state or local permit. Please refer to the full definitions of emergency generator and emergency equipment in §98.6. Portable equipment, as defined in §98.6, is also exempt from reporting.

Commenter Name: Stephen B. Kemp
Commenter Affiliation: Occidental Chemical Corporation (OCC)
Document Control Number: EPA-HQ-OAR-2008-0508-0644.1
Comment Excerpt Number: 7

Comment: In Section V.C. of the preamble to the proposed rule (74 FR 68, page 16480), the following is stated: "EPA is proposing to not require reporting of emissions from portable equipment or generating units designated as emergency generators in a permit issued by a state or local air pollution control agency. We request comment on whether or not a permit should be required for these emergency generators." EPA need not require that portable and emergency equipment and units be authorized by a permit in order to be exempt from the GHG reporting rule. The use of portable or emergency generators in the State of Texas, for example, is generally authorized by a Permit-By-Rule, and depending on the capacity of the unit, may not require the submittal of a state-specific form or document, or any receipt of confirmation from the Texas Commission on Environmental Quality. While OCC has not undertaken an exhaustive review of other state rules or requirements, we believe that other similar types of regulatory authorizations exist. We support the exclusion of portable and emergency generators from the definition of Stationary Fuel Combustion Sources. However, we believe that the language proposed at §98.40(b) should read as follows: (b) This source category does not include portable equipment or generating units designated as emergency generators issued as authorized by a State or local air pollution control agency's rules or requirements.

Response: EPA has maintained the exclusion of emergency generators, and has excluded other emergency equipment from reporting. EPA has also revised the rule language to remove the prerequisite for a state or local permit. Please refer to the full definitions of emergency generator and emergency equipment in §98.6.

Commenter Name: Paul L. Carpinone
Commenter Affiliation: Tampa Electric Company (TECO)
Document Control Number: EPA-HQ-OAR-2008-0508-0717.1
Comment Excerpt Number: 7

Comment: Proposed §93.30 and §98.40 exempt portable equipment and emergency generators from GHG emission reporting requirements. Due to the minimal GHG emissions expected from such equipment, Tampa Electric supports the equipment's exemption from the proposed reporting requirement. Because GHG emissions from such equipment are generally minimal, and because exempt emergency generators would already be required to meet the specifications listed in the definition of "emergency generators" under proposed §98.6, there is no reason to add a further restriction that the equipment be listed in a permit. In summary, for those units that meet the definition of "emergency generator" under §98.6 should be excluded from the proposed reporting requirements of applicable source categories due to their minimal GHG emission contribution.

Response: EPA has maintained the exclusion of emergency generators, and has excluded other emergency equipment from reporting. EPA has also revised the rule language to remove the prerequisite for a state or local permit. Please refer to the full definitions of emergency generator and emergency equipment in §98.6. Portable equipment, as defined in §98.6, is also exempt from reporting.

Commenter Name: Vince Brisini
Commenter Affiliation: RRI Energy Inc. (RRI)
Document Control Number: EPA-HQ-OAR-2008-0508-0618.1
Comment Excerpt Number: 6

Comment: RRI supports the exemption of portable equipment and emergency generators from GHG emission reporting requirements, but requests that U.S. EPA expand the exemption to include "limited-use generators." These generators, or "peaking units," are only used during times of peak electricity demand. Due to their limited use, minimal GHG emissions should be expected from such equipment. U.S. EPA has previously established precedence for exempting limited-use generators from a variety of monitoring and reporting requirements or emission limits (e.g., 40 CFR 60 Subpart Db NSPS for Industrial-Commercial-Institutional Steam Generating Units and 40 CFR 63 Subpart ZZZZ NESHAP for Stationary RICE). RRI proposes that limited-use generators be defined as those with a maximum annual heat input capacity factor of 5 percent for the purposes of GHG reporting requirements.

Response: See the response to comment EPA-HQ-OAR-2008-0508-0516.1 excerpt 10 for additional explanation of the treatment of load-shedding and peak-shaving units.

EPA has maintained the exclusion of emergency generators, and has excluded other emergency equipment from reporting. EPA has also revised the rule language to exclude the prerequisite for a state or local permit. Please refer to the full definition of emergency generator in §98.6: peaking units are not considered emergency generators.

Commenter Name: John H. Skinner
Commenter Affiliation: Solid Waste Association of North America (SWANA)
Document Control Number: EPA-HQ-OAR-2008-0508-0659.1
Comment Excerpt Number: 5

Comment: We support the exemption for portable equipment and generating units designated as emergency generators in a permit issued by a state or local air pollution control agency.

Response: EPA appreciates the commenter's support. EPA has maintained the exclusion of emergency generators, and has excluded other emergency equipment from reporting. EPA has also revised the rule language to remove the prerequisite for a state or local permit. Please refer to the full definitions of emergency generator and emergency equipment in §98.6. Portable equipment, as defined in §98.6, is also exempt from reporting.

Commenter Name: Andrew C. Lawrence
Commenter Affiliation: Department of Energy (DOE)
Document Control Number: EPA-HQ-OAR-2008-0508-0612.1
Comment Excerpt Number: 5

Comment: In section 98.30(b) of Subpart C – General Stationary Fuel Combustion Sources, a reporting exemption is proposed for portable equipment or generating units designated as emergency generators, if such equipment is included in a permit issued by a state or local air agency. DOE recommends that this requirement be modified to include equipment exempted from state permitting requirements. In many state and local air permit programs, emergency generators are specifically exempt from new source and Title V permit requirements through state rules, most of which are part of the State Implementation Plan (SIP). Although new generator engines may be regulated under a new source performance standard (NSPS), many sites continue to employ electrical generating equipment exempt from or not regulated by the NSPS. If necessary, EPA could mirror state rules and develop an exemption level wherein engines using certain fuels, (e.g., natural gas, fuel oil), are exempt if below a certain horsepower and restricted to a certain number of hours of use.

Response: See the Preamble for the response on de minimis reporting for small emission points.

EPA has maintained the exclusion of emergency generators, and has excluded other emergency equipment from reporting. EPA has also revised the rule language to remove the prerequisite for a state or local permit. Please refer to the full definitions of emergency generator and emergency equipment in §98.6.

Commenter Name: Scott Davis
Commenter Affiliation: Arizona Public Service (APS)
Document Control Number: EPA-HQ-OAR-2008-0508-0639.1
Comment Excerpt Number: 5

Comment: EPA states in the preamble that they are "... proposing to not require reporting of emissions from portable equipment or generating units designated as emergency generators in a permit issued by the state or local air pollution control agency." EPA is also requesting comments on whether or not a permit should be required for emergency generators. APS fully supports the exclusion of portable equipment and emergency generators from the applicability determinations and subsequent reporting requirements of this rule. It is APS's position that not only should emergency generators be excluded, but that they should be excluded regardless of whether it is identified in a state or local air pollution control permit. In many situations emergency generators are broadly addressed in air quality control permits, but are not specifically identified. They are identified only as insignificant activities or even trivial activities in the Technical Support Documents.

Response: EPA has maintained the exclusion of emergency generators, and has excluded other emergency equipment from reporting. EPA has also revised the rule language to remove the prerequisite for a state or local permit. Please refer to the full definitions of emergency generator and emergency equipment in §98.6.

Commenter Name: William Yanek
Commenter Affiliation: Glass Association of North America (GANA)
Document Control Number: EPA-HQ-OAR-2008-0508-0586.1
Comment Excerpt Number: 10

Comment: EPA proposes exempting from a facility's annual report all emissions from emergency backup generators but only if those generators are designated as emergency generators in the facility's state or local permit. See proposed 40 CFR §98.30. GANA urges EPA to eliminate this condition and instead exempt measuring and reporting the emissions from any and all emergency generators or backup engines meeting the EPA definition of "emergency generator" specified in proposed 40 CFR §98.6. The proposed definition is clear and may be consistently applied to all sites regardless of whether the backup generator or engine has been designated as such in a facility permit. Given that definition, their emissions, if any, would be de minimis under any reasonable measure and thus would not affect the overall quality of the emissions data for the facility.

Response: EPA has maintained the exclusion of emergency generators, and has excluded other emergency equipment from reporting. EPA has also revised the rule language to remove the prerequisite for a state or local permit. Please refer to the full definitions of emergency generator and emergency equipment in §98.6.

Commenter Name: D. Lawrence Zink
Commenter Affiliation: Montana Sulphur & Chemical Company Inc. (MSCC)
Document Control Number: EPA-HQ-OAR-2008-0508-0505.1
Comment Excerpt Number: 3

Comment: We believe that there is no need for portable or emergency equipment, either permitted or not permitted, to be exempt or excluded from the proposed rule for two reasons. 1) It is difficult to carve out the emissions related to these specific units; and 2) even if such equipment were to be exempted on the downstream side, the fuel suppliers would include the supply used for such equipment. The proposed rule does not provide much discussion on this topic. What is the rationale for any such exemption?

Response: The Agency disagrees with the commenter's assertion that there is no need for the portable or emergency equipment to be excluded from reporting, and has exempted portable or emergency equipment, as defined in §98.6, from reporting in the final rule (see §98.30(b)). The Agency has concluded that reporting emissions from emergency equipment would be unduly burdensome in relation to the amount of emissions that would be captured. An explanation is provided in the Preamble in Section III. C. 3., "General Stationary Fuel Combustion Sources." However, EPA wishes to clarify that a source may include emissions from these devices if separating emissions from them would prove onerous. As discussed in Section II. D. 3. of the Preamble, "Summary of Comments and Responses on Source Categories to Report," the requirements for upstream and downstream reporting may lead to double reporting in some cases. It has never been EPA's intention to make upstream and downstream coverage match exactly, and in fact one of the advantages of upstream coverage is that it is able to provide information on fuel used in small devices or mobile sources where downstream reporting is burdensome.

Commenter Name: Karen S. Price
Commenter Affiliation: West Virginia Manufacturers Association (WVMA)
Document Control Number: EPA-HQ-OAR-2008-0508-0475.1
Comment Excerpt Number: 5

Comment: Under the proposed rule, portable equipment or generating units are excluded from the fuel combustion source category designated, as long as they are used for emergency purposes only. As proposed, the units must be designated as "emergency generators" in a permit issued by a state or local air pollution control agency. In addition, the proposed rule does not exempt engines that serve as back-up power sources under conditions of load shedding, peak shaving, power interruption pursuant to an interruptible power source agreement, or scheduled maintenance. While the WVMA is supportive of an exemption for emergency generators, we believe that the definition of emergency generator should be broadened and should not require that such engine be permitted as an emergency generator. In addition, we think that emergency engines used for the reasons cited above should also be exempted from the reporting rule.

Response: EPA has maintained the exclusion of emergency generators, and has excluded other emergency equipment from reporting. EPA has also revised the rule language to remove the prerequisite for a state or local permit. In §98.6, however, EPA has specifically excluded from the definition of emergency generators engines that serve as back-up power sources under conditions of load shedding, peak shaving, power interruptions pursuant to an interruptible power source agreement, or scheduled maintenance, and as such, from the exemption from reporting.

Commenter Name: See Table 4
Commenter Affiliation:
Document Control Number: EPA-HQ-OAR-2008-0508-0455.1
Comment Excerpt Number: 5

Comment: Proposed §§98.30 and 98.40 would exempt portable equipment and emergency generators from GHG emission reporting requirements, but not other types of stationary emergency equipment. The Class of '85 believes that this exemption should be expanded to cover other types of emergency equipment. Specifically, the Class of '85 believes that emergency diesel-fired firewater pumps and emergency boiler feed water pumps should be exempted from GHG reporting requirements due to their infrequent use and minor emissions. These pumps are almost never used, except for emergencies or periodic function tests. However, they do not fit under the proposed emergency generator and portable equipment exemption because they are typically permanently mounted in their own small buildings. Thus, the Class of `85 urges EPA to expand the proposed emergency generator and portable equipment exemption to include all emergency equipment that meets the use specifications listed in the definition of "emergency generators" under proposed §98.6.

Response: EPA has maintained the exclusion of emergency generators, and has excluded other emergency equipment from reporting. Please refer to the full definitions of emergency equipment in §98.6 in which emergency equipment means any auxiliary fossil fuel-powered equipment, such as a fire pump, that is used only in emergency situations. EPA is also excluding portable equipment from reporting. Please refer to the full definition of portable equipment in §98.6.

Commenter Name: Gary Moore
Commenter Affiliation: Pensacola Plant of Ascend Performance Materials LLC
Document Control Number: EPA-HQ-OAR-2008-0508-0366.1
Comment Excerpt Number: 4

Comment: Many manufacturing facilities operate "burnout furnaces" whose purpose is to clean parts of plastics, oil or other residual material prior to the part being used in a subsequent manufacturing process. These burnout furnaces appear to meet the definition of incinerator in §98.30. Burnout furnaces typically have relatively low BTU heat inputs, for example less than 3 MMBtu/hr and often under 500,000 Btu/hr and do not operate continuously. Burnout furnaces would typically be classified as a Parts Reclamation Unit under CIWSI rules (40 CFR 60 Subpart DDDD or 40 CFR 62 Subpart III). Are the materials burned off of the parts considered fuel under the proposed rule? It would be burdensome and expensive to weigh and track the parts before and after cleaning. In addition, the parts may be required to be placed in service in a hot state. This would involve reheating parts after final cleaning and weighing. The amount of material is generally small and would not be a significant contributor of Greenhouse Gas emissions. We propose exempting Parts Reclamation Units as currently defined in the CIWSI rules.

Response: EPA believes that the content of the final rule addresses this comment through the revision of of the applicability of the tiers in the final rule. It is EPA's intent that Tier 1 and 2 sources, which are allowed for combustion devices rated at 250 mmBtu/hr and less, will only be required to report emissions from the combustion of fuels for which emission factors are provided. Units larger than 250 mmBtu/hour heat input GHG that combust miscellaneous, non-traditional fuels such as refinery gas, process gas, vent gases, waste liquids, and others must report only if CEMS are used or if these fuels contribute ten percent or more of the annual unit heat input to the unit. With this exclusion, we have concluded that devices such as thermal oxidizers, pollution control devices, fume incinerators, burnout furnaces, and other such equipment would report only GHG emissions from the firing of supplemental fossil fuels.

Commenter Name: Laurie Zelnio
Commenter Affiliation: Deere & Company
Document Control Number: EPA-HQ-OAR-2008-0508-0355.1
Comment Excerpt Number: 4

Comment: As a manufacturer of nonroad engines and mobile equipment, Deere facilities may also combust fuels for the purpose of nonroad engine and product research, development, and testing. Sources of these emissions include engine test cells/test stands, equipment on dynamometers, and our mobile equipment at the end of the assembly line. We submitted a question to the EPA to clarify whether fuel consumed for testing nonroad engines and nonroad equipment is included in the reporting. We received a response to our inquiry indicating that research and development of engines are not exempt from reporting. This conflicts with information the Outdoor Power Equipment Institute (OPEI), of which we are a member, received from Katherine Sibold, Program Integration Branch, USEPA – Office of Air and Radiation, that emissions from engines will be captured under the reporting requirements for engine manufacturers; therefore reporting of emissions from engines at the facility would not be required. Further clarification is needed -- are we required to report both for affected facilities and as an engine manufacturer? Furthermore, in the State of Iowa, mobile equipment that vents through a stationary stack is not considered "mobile" which would normally be exempt from construction permitting under IAC 567 22.1(2)c. and is normally considered insignificant for Title V under IAC 567 22.103(1)a. It is not clear in the proposed rule if this same interpretation applies to the definition of a stationary fuel combustion source at §98.30. Clear segregation of mobile source emission reporting from stationary source emission reporting is needed. To eliminate double-reporting and to clarify what this Federal rule includes as a stationary source, Deere recommends "research, development, and testing of mobile source engines and mobile source equipment" be added to the exclusion in §98.3(b).

Response: See the individual source category section(s) of the Preamble and the source category comment response document(s) for the response on the definition of the source category. EPA is also excluding portable equipment from reporting. Please refer to the full definitions of portable equipment in §98.6. Stationary combustion devices that do not meet the definition of portable equipment would be expected to be reported.

EPA has established a clear segregation of mobile source emission rate reporting from stationary source emission reporting. The determination of coverage under §98 is separate from the determination of coverage under §86 for emissions rates from mobile sources. See the Preamble section and separate comment response document volume on Mobile Sources for an explanation of coverage under that Part.

Please refer to the exclusion of research and development activities in §98.2, and the definition of research and development in §98.6.

Emissions from engine testing that are not R&D activities need to be reported under the Stationary Combustion source category if the source is fixed (e.g.,to a foundation). However, the final rule includes additional flexibility on the use of the tier methods. Depending on the size of the engines being tested, Tier 1 and/or the alternative reporting requirements which allow the aggregation of small units may be applicable, both of which may reduce the burden of reporting.

Commenter Name: Kathleen Tobin
Commenter Affiliation: Verizon Communications, Inc.
Document Control Number: EPA-HQ-OAR-2008-0508-0575.1
Comment Excerpt Number: 4

Comment: Currently, States track emergency engine use in a variety of ways from simple notifications through full permitting, depending on local air quality concerns as well as the size and usage of the generators. Exempting only portable equipment or emergency engines with a permit could cause a large number of equipment or engines to be covered under this proposal by the mere fact that permits are not necessarily required. Emergency engines are defined in the regulation; therefore, it would seem unnecessary to include units that operate in the same manner simply because they are not required to have a state or local permit. One unanticipated effect of exempting only emergency engines with a permit would be to increase the number of permit applications in states where emergency engines are not required to be fully permitted in order to qualify for this exemption. This may increase requests for permits that would result in an administrative burden without any substantive environmental gain. Therefore, the exemption should cover all emergency engines, including non-permitted units under its emergency generator exemption.

Response: EPA has maintained the exclusion of emergency generators, and has excluded other emergency equipment from reporting. EPA has also revised the rule language to exclude the prerequisite for a state or local permit. Please refer to the full definitions of emergency generator and emergency equipment in §98.6.

Commenter Name: Angela Burckhalter
Commenter Affiliation: Oklahoma Independent Petroleum Association (OIPA)
Document Control Number: EPA-HQ-OAR-2008-0508-0386.1
Comment Excerpt Number: 21

Comment: Under Tier 3, EPA requires direct measurement of the amount of fuel combusted. Most combustion sources at oil and gas production facilities do not have fuel flow meters installed. Did EPA account for the cost of adding fuel flow meters into its cost impact analysis?

Response: EPA has considerably revised §98.33(b), describing which tier a reporter is to use. Tier 2, which allows facilities to determine fuel use from company records, is now applicable to units of any size combusting pipeline natural gas or distillate fuel oil. EPA has defined the term "company records" in §98.6 of the final rule, and believes that the revised definition provides appropriate guidance as to what records a facility may use to determine fuel consumption. While fuel flow meters may be used where company records are required, they are certainly not mandatory. EPA has also clarified in the final rule that fuel billing meters may be used for the purpose of directly measuring combustion of liquid and gaseous fuels in Tier 3. Meanwhile, EPA has retained the provisions in Tier 3 allowing facilities to determine fuel oil consumption using tank drop measurements and solid fuel combustion using company records for the purposes of Tier 3 calculations. EPA believes that these provisions provide an appropriate balance between reducing the reporting burden and gathering accurate data. Taking this into consideration, EPA has accounted for the cost for the installation of flow meters, where applicable.

Commenter Name: See Table 4
Commenter Affiliation:
Document Control Number: EPA-HQ-OAR-2008-0508-0455.1
Comment Excerpt Number: 4

Comment: Proposed §§98.30 and 98.40 would exempt portable equipment and emergency generators from GHG emission reporting requirements. Due to the minimal GHG emissions expected from such equipment, the Class of '85 supports the equipment's exemption from the proposed reporting requirements. However, the Group believes that EPA has crafted the proposed exemption too narrowly. Under proposed §§98.30 and 98.40, only portable equipment and emergency generators that are designated as emergency generators in a permit issued by a state or local air pollution control agency would be exempt from the reporting requirements of the regulation. The Class of '85 believes that the permit designation restriction is unnecessary. Because GHG emissions from such equipment are generally minimal, and because exempt emergency generators would already be required to meet the specifications listed in the definition of "emergency generators" under proposed §98.6, there is no reason to add a further restriction that the equipment be listed in a permit. Some states exempt emergency generators from construction or operating permits if certain operating criteria are met. For example, in Wisconsin an emergency electric generator means "an electric generator whose purpose is to provide electricity to a facility if normal electrical service is interrupted and which is operated no more than 200 hours per year." Wis. ADMIN. CODE NR § 400.02(56). An emergency electrical generator fitting this definition is exempt from construction or operating permit requirements provided it is "powered by internal combustion engines which are fueled by gaseous fuels, gasoline or distillate fuel oil with an electric output of less than 3,000 kilowatts." Wis. ADMIN. CODE NR §§406.04(1)(w) and 407.03(1)(u)). As a result of such state exemptions, emergency generators may be designated as emergency generators by the state, but not included in the state or local air pollution control agency permit. For these reasons, the Class of '85 believes that proposed §§98.30 and 98.40 should be revised to simply state that portable equipment and emergency generators that meet the definition of "emergency generators" under §98.6 are excluded from the proposed reporting requirements of applicable source categories. At the least, EPA should expand the exemption to apply not only to emergency generators that are exempted by permit but also to emergency generators that are exempted from permitting.

Response: EPA has maintained the exclusion of emergency generators, and has excluded other emergency equipment from reporting. EPA has also revised the rule language to remove the

prerequisite for a state or local permit. Please refer to the full definitions of emergency generator and emergency equipment in §98.6.

Commenter Name: Paul Dubenetzky
Commenter Affiliation: KERAMIDA Inc.
Document Control Number: EPA-HQ-OAR-2008-0508-0419.1
Comment Excerpt Number: 7

Comment: Maintain and clarify the exemption for portable equipment (varies, most refer to 40 CFR 98.30(b), portable equipment defined at 40 CFR 98.6 74 FR 16625).

Response: EPA has maintained the exclusion of portable equipment, as defined in §98.6, from reporting under both Subpart C and Subpart D.

Commenter Name: Randal G. Oswald
Commenter Affiliation: Integrys Energy Group, Inc.
Document Control Number: EPA-HQ-OAR-2008-0508-0569.1
Comment Excerpt Number: 3

Comment: We support EPA's proposal to not require reporting of emissions from portable equipment or generating units designated as emergency generators. However, the designation of an emergency generator should be expanded to include those designated as emergency generation by regulation. EPA's proposal restricts no-reporting to emergency generators that are so designated by permit. However some states may exempt certain emergency generators from construction or operating permit requirements. The exemption applies when certain operating criteria are met. For example, in the Wisconsin Administrative Code (WAC), an emergency electric generator "means an electric generator whose purpose is to provide electricity to a facility if normal electrical service is interrupted and which is operated no more than 200 hours per year." (WAC NR 400.02(56)). An emergency electrical generator is exempt from construction or operation permit requirements provided it is "powered by internal combustion engines which are fueled by gaseous fuels, gasoline or distillate fuel oil with an electric output of less than 3,000 kilowatts." (WAC NR 406.04(1)(w) and WAC NR 407.03(1)(u)). The no-reporting feature of the proposed rule should be expanded to include emergency units that are also designated by regulation as emergency generators.

Response: EPA has maintained the exclusion of emergency generators, and has excluded other emergency equipment from reporting. EPA has also revised the rule language to remove the prerequisite for a state or local permit. Please refer to the full definitions of emergency generator and emergency equipment in §98.6.

Commenter Name: Angela D. Marconi
Commenter Affiliation: Delaware Solid Waste Authority
Document Control Number: EPA-HQ-OAR-2008-0508-0472.1
Comment Excerpt Number: 2

Comment: Section I of the preamble discusses a variety of greenhouse gases and the difference between gases that are biogenic and anthropogenic in nature. Section HH-Landfills notes that the CO_2 portion of landfill gas (LFG) as well as any CO_2 created from destruction of CH_4, is not anthropogenic. Section 98.342 of the rule specifically excludes CO_2 from flare emissions from required reporting, and it does not comment on fugitive CO_2 emissions. However, there is some confusion as to whether section 98.33(b)(5)(ii) excludes engines that utilize landfill gas from reporting CO_2 emissions. Please clarify that engines that utilize LFG are excluded from CO_2 emissions. DSWA agrees with this characterization and recommends that emissions that are not anthropogenic should be excluded from the inventory. Including biogenic emissions in the inventory will cause confusion because these emissions do not contribute to the greenhouse effect. Additionally, the tracking of these emissions will require additional effort and expense without gaining useful information.

Response: EPA disagrees with the suggestion that biogenic CO_2 should not be reported, and in fact requires facilities to track biogenic emissions separately. Including reporting of biogenic CO_2 at facilities that are already reporting for stationary combustion provides EPA with information on the use of biofuels as they relate to reductions of fossil CO_2 emissions over time. This reporting requirement also provides additional data for verification. EPA believes that it is clear in §98.2, however, that CO_2 emissions from biogenic fuels do not count toward the 25,000 metric ton threshold for reporting for stationary combustion units, although CH_4 and N_2O emissions from biogenic fuels must be considered when calculating the threshold and determining applicability.

EPA has added a provision to §98.33(e) specifying that Tier 1 may be used to calculate emissions from the combustion of any biogenic fuel (including landfill gas), as long as CEMS are not used to measure CO_2 emissions. EPA has added to Table C-1 a default biogas (landfill gas) emission factor. EPA has added language to §98.33(b)(4) to clarify that all of the criteria in §98.33(b)(4)(ii) or (iii) must be present to require the use of Tier 4. EPA has also specifically excluded flares from the stationary combustion source category in §98.30, except where reporting of flare emissions is required by another subpart of Part 98.

Commenter Name: Gary Moore
Commenter Affiliation: Pensacola Plant of Ascend Performance Materials LLC
Document Control Number: EPA-HQ-OAR-2008-0508-0366.1
Comment Excerpt Number: 1

Comment: It is unclear from the definition of Stationary Fuel Combustion Sources in §98.30 whether flares, thermal oxidizers or other thermal control devices are classified as a Stationary Fuel Combustion Source under the rule. These type of units exist to control off gas emissions under various Federal and state rules such as the Hazardous Organic NESHAP (HON) in 40 CFR 63 Subparts F, G and H; Miscellaneous Organic NESHAP (MON) in 40 CFR 63 Subpart FFFF or Prevention of Significant Deterioration (PSD) permitting process. The offgas streams typically do not independently support combustion. The purpose of operation for these control devices does not fit the "Generally for the purposes of statement in §98.30. Their main control devices may have waste heat recovery installed but their primary reason for operation is not steam generation. Greenhouse Gas emission calculation methods for flares appear in other sections of the proposed rule but not in the proposed Subpart C. Thermal control devices should be excluded from Stationary Fuel Combustion Sources.

Response: See the General Stationary Combustion source category Preamble section, as well as the separate comment response document, for the response on the definition of the source category.

EPA acknowledges the concerns of the commenter and has revised §98.33 to deal with certain unconventional combustion processes and types of fuel. It is EPA's intent that sources allowed to use the Tier 1 and 2 methods, which include smaller combustion devices and should be inclusive of control devices such as thermal oxidizers, will only be required to report emissions from the combustion of fuels for which emission factors are provided. In the Preamble, EPA has explained that "EPA believes that the reporting requirements for Tier 1 and Tier 2 would only require the reporting of GHG emissions from supplementary traditional fossil fuels from devices such as thermal oxidizers, pollution control devices, fume incinerators, burnout furnaces, and other such equipment." EPA believes that these provisions satisfy the intent of Part 98, to collect accurate and consistent GHG emissions data that can be used to inform future decisions.

Commenter Name: Jerry Call
Commenter Affiliation: American Foundry Society (AFS)
Document Control Number: EPA-HQ-OAR-2008-0508-0356.2
Comment Excerpt Number: 4

Comment: The term, "stationary fuel combustion source," should also not include cupolas. A cupola is a vertical, cylindrical furnace where the principal fuel, coke, is used in conjunction with metallics and fluxes to produce molten metal. The metallics are melted in the cupola by the release of heat from the combustion of carbon from the coke. The examples of stationary fuel combustion sources that are provided in section 98.2(a)(3) of the proposed regulation include: boilers, combustion turbines, engines, incinerators, and process heaters. While EPA does not provide a definition of "process heater" in the proposed rule, a review of the vacated National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters (69 Fed. Reg. 55269) provided the following definition: "process heater means 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. Process heaters do not include units used for comfort heat or space heat, food preparation for on-site consumption, or autoclaves. The cupola transfers heat directly to the material it is processing and does not, therefore, meet this definition nor is a cupola similar to any of the other examples of stationary fuel combustion sources provided in the proposed regulation.

Response: See the individual source category sections of the Preamble and the source category comment response documents for the responses on source category-specific reporting requirements.

It is EPA's intent that cupola furnaces report GHG emissions according to the requirements for combustion units discussed in detail in Subpart C of the final rule, as the majority of the GHG emissions originate from fuel combustion. Applicability of Subpart C reporting requirements is not limited to the sources identified in the list of examples noted in the comment, as clarified with the words in the rule text immediately preceding it, "including, but not limited to." The Preamble section for Subpart Q, Iron and Steel Production, provides a list that identifies the types of units with similar properties to cupola furnaces for which the Subpart C reporting requirements apply for estimating CO_2, CH_4, and N_2O emissions.

Commenter Name: Jerry Call
Commenter Affiliation: American Foundry Society (AFS)
Document Control Number: EPA-HQ-OAR-2008-0508-0356.2
Comment Excerpt Number: 3

Comment: AFS agrees that the term, "fuel combustions sources," should not include portable equipment or generating units designated as emergency generators. However, because of state construction permit exemptions, the requirement that these units be designated as such with a permit issued by a state or local air pollution control agency is unnecessary and unduly burdensome and should be deleted from the proposed regulation.

Response: EPA has maintained the exclusion of emergency generators, and has excluded other emergency equipment from reporting. EPA has also revised the rule language to remove the prerequisite for a state or local permit. Please refer to the full definitions of emergency generator and emergency equipment in §98.6.

Commenter Name: Cindy Parsons
Commenter Affiliation: Los Angeles Department of Water and Power
Document Control Number: EPA-HQ-OAR-2008-0508-0228t
Comment Excerpt Number: 3

Comment: Notice that the proposed reporting rule exempts portable equipment and emergency generators but overlooks other types of emergency backup engines with insignificant emissions, such as emergency fire pumps and emergency backup water pumps. EPA should consider expanding the exemption to include all types of emergency backup engines so that all emergency engines are treated the same.

Response: EPA has maintained the exclusion of emergency generators, and has excluded other emergency equipment from reporting. EPA has also revised the rule language to remove the prerequisite for a state or local permit. Please refer to the full definitions of emergency generator and emergency equipment in §98.6.

Commenter Name: Robert J. Martineau, Jr
Commenter Affiliation: Counsel, Waller Lansden Dortch & Davis, LLP
Document Control Number: EPA-HQ-OAR-2008-0508-0414.1
Comment Excerpt Number: 4

Comment: EPA specifically has solicited comment on whether the exclusion for portable or emergency generators under various provisions of the rule should be contingent on whether they are so designated in a permit. See e.g. 74 Fed.Reg. at 16,462. (fns. 32 & 33). Nissan urges EPA not to require that the portable emergency generator unit be designated as such in a permit. State and local permitting programs have a myriad of detailed permitting requirements. There is certainly no uniform approach with respect to whether portable generating units are typically included in a permit. The decision to exclude portable generating units used as emergency generators in those permitting programs should not be the basis for determining whether or not to include such units. The basis should be the intended nature of the unit themselves — portable equipment or emergency generators and the de minirnis nature of their emissions.

Response: EPA has revised the rule language to exclude the prerequisite for a state or local permit. Please refer to the full definitions of emergency generator, portable equipment, and emergency equipment in §98.6.

Commenter Name: Michael W. Stroben
Commenter Affiliation: Duke Energy Corporation
Document Control Number: EPA-HQ-OAR-2008-0508-0407.1
Comment Excerpt Number: 9

Comment: Duke Energy requests that EPA clarify that the definition of "portable" is not intended to include small non-road equipment used at a site for various facility support services. For example, it seems that exclusion for equipment that remains on site for more than 12 consecutive months could require that facilities track and report the emissions from lawnmowers, pressure washers, and similar small engines that are used for infrequent non-process activities.

Response: See the Preamble for the response on de minimis reporting for small emission points.

We are retaining the existing definition of portable equipment in §98.6, which includes language that "Indications of portability include but are not limited to wheels, skids, carrying handles, dolly, trailer, or platform." The definition of portable excludes "equipment or a replacement that resides at the same location for more than 12 consecutive months. The types of equipment mentioned by the commenter would typically not be excluded from the definition because while they reside at the same facility they would very likely not reside at the same exact location for more than 12 consecutive months because of their intended use.

Commenter Name: Chris Hornback
Commenter Affiliation: National Association of Clean Water Agencies (NACWA)
Document Control Number: EPA-HQ-OAR-2008-0508-0566.1
Comment Excerpt Number: 13

Comment: NACWA supports the proposed exclusion of emissions from emergency power generators. Many emergency units may be permitted by rule in some states or not specifically permitted by the state. NACWA believes that all emergency power generators should be excluded, regardless of whether or not they are specifically permitted.

Response: EPA has maintained the exclusion of emergency generators, and has excluded other emergency equipment from reporting. EPA has also revised the rule language to remove the prerequisite for a state or local permit. Please refer to the full definitions of emergency generator and emergency equipment in §98.6.

Commenter Name: Michael Bradley
Commenter Affiliation: The Clean Energy Group (CEG)
Document Control Number: EPA-HQ-OAR-2008-0508-0479.1
Comment Excerpt Number: 16

Comment: The Clean Energy Group requests clarification from EPA that generators of geothermal electricity do not have to report under the proposed rule. The rule does not directly address geothermal electricity production, which is a renewable electricity resource. If EPA determines that geothermal electricity production should be included in the rule as a source category, the Clean Energy Group requests clarification on the method by which greenhouse gas emissions would be calculated in order to determine applicability. Greenhouse gas emissions from geothermal vary widely from well to well and unit to unit, and a single emission factor would not be accurate. For example, standard California ARB factors substantially overestimate greenhouse gas emissions from geothermal processes, often by approximately fourfold. The Clean Energy Group agrees with the exemption that EPA is proposing for portable equipment or generating units designated as emergency generators in a permit issued by a state or local air pollution control agency. However, there are variations from state to state regarding the regulation of these sources including whether a permit is required or what constitutes an emergency generator. Additionally, designation as an emergency generator has consequences for regulation under other federal and state air pollution control programs. EPA should eliminate the permit requirement from this definition, and instead define emergency generator separately for the purpose of this exemption and make it clear that emergency generators are exempt from every source category and not only electricity generation.

Response: See the Preamble and separate comment response document volume for the response on selection of source categories to report. Facilities must report GHG emissions for sources for which methodologies are provided, and EPA has not provided a methodology for CO_2 emissions from non-combustion geothermal energy generation processes.

EPA acknowledges the concerns of the commenter. Section 98.40 of the final rule clarifies the definition of the electricity generation source category. Facilities are required to report GHG emissions under Subpart D only if the facility contains one or more electricity generating units that: 1) are subject to the requirements of the Acid Rain Program; or 2) are required to monitor and report to EPA CO_2 emissions year-round according to Part 75.

EPA has maintained the exclusion of emergency generators, and has excluded other emergency equipment from reporting. EPA has also revised the rule language to remove the prerequisite for a state or local permit. Please refer to the full definitions of emergency generator and emergency equipment in §98.6.

A geothermal electricity production facility that has stationary combustion devices emitting greater than 25,000 tons of CO_2e would be required to report under Subpart C.

Commenter Name: Kathleen M. Sgamma
Commenter Affiliation: Independent Petroleum Association of Mountain States (IPAMS)
Document Control Number: EPA-HQ-OAR-2008-0508-0521.1
Comment Excerpt Number: 15

Comment: Not all states require permits for emergency generators. In addition to excluding permitted generators, the exclusion should extend to non-permitted emergency equipment (such as non-permitted emergency generators or fixed firewater pumps).

Response: EPA has maintained the exclusion of emergency generators, and has excluded other emergency equipment from reporting. EPA has also revised the rule language to remove the prerequisite for a state or local permit. Please refer to the full definitions of emergency generator and emergency equipment in §98.6.

Commenter Name: Robert J. Martineau, Jr
Commenter Affiliation: Counsel, Waller Lansden Dortch & Davis, LLP
Document Control Number: EPA-HQ-OAR-2008-0508-0414.1
Comment Excerpt Number: 15

Comment: Nissan requests clarification as to whether GHG emissions that result from the testing and inspection process of light-duty vehicle engines, during the engine manufacturing process, are properly excluded from a manufacturing facility's reporting requirements under the fuel combustion source category as they will accounted for in the Mobile Sources category. During the engine manufacturing process, individual engines are placed on a carousel and tested in operation to ensure proper operation prior to being permanently installed in the vehicle. The resulting engine emissions are channeled to a central collection location and emitted. Nissan believes that these emissions are not included in the fuel combustion source category but requests clarification of the issue. Nissan's position is supported by language in the preamble discussing the fuel combustion category. The relevant preamble language states: "[s]tationary fuel combustion sources are devices that combust solid, liquid, or gaseous fuel generally for the purpose of producing electricity, generating steam, or providing useful heat or energy for industrial, commercial, or institutional use, or reducing the volume of waste by removing combustible matter." 74 Fed. Reg., at 16,480. The consequential GHG emissions resulting from the combustion of fuel in the test engines on the carousel do not serve any of the purposes described in the definition of a General Stationary Fuel Combustion source category. Thus, Nissan does not believe the fuel combustion from the test engines should be accounted for in calculating GHG emissions from its manufacturing facility as a stationary source. As discussed above, we request clarification as to whether GHG emissions resulting from individual engine testing processes at the engine manufacturing facility are properly reported under the Mobile Sources category, or whether such emissions must also be reported in a duplicative fashion under other source categories, namely the General Stationary Fuel Combustions category.

Response: EPA notes that the mobile source reporting provisions are for reporting emissions rates and not absolute emissions, and therefore emissions coming from the activities listed by the commenter would in any case not be reported under the mobile source provision.

See the General Stationary Combustion source category section of the Preamble and the separate comment response document volume for the response on the definition of portable equipment in §98.6, which includes language that "Indications of portability include but are not limited to wheels, skids, carrying handles, dolly, trailer, or platform." EPA's intent is that emissions from stationary combustion devices that do not meet the definition of portable equipment would be reported under Subpart C.

Please refer to the exclusion of research and development activities in §98.2 that has been added to the final rule, and the definition of research and development in §98.6.

If the sources referenced by the commenter do not meet the definition of research and development, the commenter should note that emissions from engine testing need to be reported under the Stationary Combustion source category if the source is fixed (e.g., to a foundation). However, the final rule includes additional flexibility on the use of the tier methods. Depending on the size of the engines being tested, Tier 1 and/or the alternative reporting requirements which allow the aggregation of small units may be applicable, both of which may reduce the burden of reporting.

Commenter Name: Kathleen M. Sgamma
Commenter Affiliation: Independent Petroleum Association of Mountain States (IPAMS)
Document Control Number: EPA-HQ-OAR-2008-0508-0521.1
Comment Excerpt Number: 14

Comment: IPAMS remains opposed to requiring the reporting of greenhouse gas emissions from temporary or portable equipment.

Response: EPA has maintained the exclusion of emergency generators, has excluded other emergency equipment from reporting, and has exempted portable equipment from reporting. Please refer to the full definitions of emergency generator, portable equipment, and emergency equipment in §98.6.

Commenter Name: Paul Dubenetzky
Commenter Affiliation: KERAMIDA Inc.
Document Control Number: EPA-HQ-OAR-2008-0508-0419.1
Comment Excerpt Number: 13

Comment: Many industrial processes combust volatile organic compound (VOC) emissions in air pollution control devices, boilers, and industrial heaters, with or without supplemental fuel. The general applicability and reporting of the GHG emissions generated by the combustion of process VOCs is generally not addressed by the proposed rule (requirements for refinery gas combustion being duly noted). The unstated treatment of these emissions falls predominately within 40 CFR 98, Subpart C — General Stationary Fuel Combustion Sources. KERAMIDA suggests that the U.S. EPA add 40 CFR 98.30(c) to state, "This source category does not include emissions of GHG resulting from the combustion of volatile organic compounds generated by industrial processes that are directed to air pollution control devices, boilers, or process heaters for the primary purpose of air pollution control. This source category does include the GHG emissions resulting from fossil fuels that are combusted in air pollution control devices, boilers, or process heaters."

Response: See the General Stationary Combustion source category Preamble section, as well as the separate comment response document volume, for the response on the definition of the source category.

EPA acknowledges the concerns of the commenter and has revised the Preamble and §98.33 to deal with certain unconventional combustion processes and types of fuel. It is EPA's intent that sources allowed to use the Tier 1 and 2 methods, which include smaller combustion devices and should be inclusive of control devices such as thermal oxidizers, will only be required to report emissions from the combustion of fuels for which emission factors are provided. In the Preamble, EPA has explained that "EPA believes that the reporting requirements for Tier 1 and Tier 2 would only require the reporting of GHG emissions from supplementary traditional fossil fuels from devices such as thermal oxidizers, pollution control devices, fume incinerators, burnout furnaces, and other such equipment."

Commenter Name: Steven M. Maruszewski
Commenter Affiliation: Pennsylvania State University (Penn State)
Document Control Number: EPA-HQ-OAR-2008-0508-0409.1
Comment Excerpt Number: 5

Comment: Penn State agrees with the exclusion of emergency generators. Including these would cause an undue reporting burden.

Response: EPA appreciates the commenter's support, and has maintained the exclusion of emergency generators from reporting. Please refer to the full definition of emergency generator in §98.6.

Commenter Name: Charlie Burd and Nicholas DeMarco
Commenter Affiliation: Independent Oil and Gas Association of West Virginia (IOGA-WV) and West Virginia and Natural Gas Association (WVONGA)
Document Control Number: EPA-HQ-OAR-2008-0508-0516.1
Comment Excerpt Number: 10

Comment: Under the proposed rule, portable equipment or generating units are excluded from the fuel combustion source category designated, as long as they are used for emergency purposes only. As proposed, the units must be designated as "emergency generators" in a permit issued by a state or local air pollution control agency. In addition, the proposed rule does not exempt engines that serve as back-up power sources under conditions of load shedding, peak shaving, power interruption pursuant to an interruptible power source agreement, or scheduled maintenance. While the WV Associations are supportive of an exemption for emergency generators, we believe that the definition of emergency generator should be broadened and should not require that such engine be permitted as an emergency generator. In addition, we think that emergency engines used for the reasons cited above should also be exempted from the reporting rule.

Response: Because of the need for comprehensive, national greenhouse gas emissions data, the final rule provides only limited exclusions from the reporting requirements. In the final rule, EPA has maintained the exclusion of emergency generators, has removed for such generators the 100-hour limitation and the requirement of designation in a state or local permit, and has excluded other emergency equipment from reporting. However, engines that serve as back-up power sources under conditions of load shedding, peak shaving, power interruption pursuant to an interruptible power source agreement, or scheduled maintenance are not emergency generators and are not excluded. This is because these operations are not necessarily infrequent, the equipment involved can be of widely varying sizes, and so the GHG emissions from these operations cannot be assumed to be, and treated as, insignificant.

Commenter Name: W. Walter Tyler
Commenter Affiliation: INVISTA S.a r.l. (INVISTA)
Document Control Number: EPA-HQ-OAR-2008-0508-0481.2
Comment Excerpt Number: 6

Comment: Clarify the obligation to report emissions from stationary sources only once. Section 98.30 of the proposed rule specifies source-specific reporting for Stationary Fuel Combustion Sources including, but not limited to "boilers, combustion turbines, engines, incinerators, and process heaters." Reporting of emissions from combustion sources is also included in other specific subparts: 1. Subpart D – Electricity Generation. Per section 98.43(b) for units not subject to the Acid Rain Program, "emissions shall be calculated using the methods specified in §98.33 for stationary fuel combustion units." 2. Subpart E – Adipic Acid Production. Per section 98.52(b), facilities must report GHG emissions from "each stationary combustion unit that uses a carbon-based fuel, following the requirements of Subpart C of this part." 3. Subpart V – Nitric Acid Production. Per section 98.222(b), facilities must report GHG emissions from "each stationary combustion unit. You must follow the requirements of Subpart C of this part." INVISTA's facilities are subject to both Subpart C and other subparts. The rule should be clarified to ensure that combustion emissions from a given unit at a site are to be reported only once, that is, under only one of the applicable subparts. Otherwise, certain facilities may be subject to double counting of emissions that would serve no stated purpose in the rule, nor would it lead to any increased accuracy in emissions estimates and reporting. Accordingly, INVISTA requests that the reporting requirement in Subpart C be clarified to ensure reporting of emissions only once from sources covered by more than one subpart. INVISTA suggests the following modification to section 98.32: You must report CO_2, CH_4, and N_2O mass emissions from each stationary fuel combustion unit. Combustion emissions reported under other source specific categories (e.g. Electricity Generation, Adipic Acid Production, Nitric Acid Production, etc.) should not be included in combustion emissions reported in the General Stationary Fuel Combustion category.

Response: See the individual source category section(s) of the Preamble and the source category comment response document(s) for the response on the definition of the source category.

EPA intends that the stationary combustion source category include any device that meets the definition included in §98.30 for which emissions are not accounted for in the report through a separate subpart of the rule. Per the requirements in 40 CFR Part 98, Subpart A, facilities have to report GHG emissions from all source categories located at their facility, including stationary combustion and process emissions. EPA does not intend that emissions be double reported, and has revised the various subparts of the final rule to clarify the intent of the stationary combustion source category.

Commenter Name: Rechelle Hollowaty
Commenter Affiliation: Tyson Foods, Inc.
Document Control Number: EPA-HQ-OAR-2008-0508-0379.1
Comment Excerpt Number: 9

Comment: For many years EPA's position as proven through their own White Paper on Emergency Generators, has been that permits are not required for emergency generators or fire pumps operating less than 500 hours per year. This has been the rational for keeping hour logs on both emergency generators and fire pumps as means of verifying compliance that these units are not being used for peak shaving. For EPA to consider requiring these type of units to become permitted has no precedence and would require a tremendous amount of additional workload for industry and state agencies. This type of permitting on top of an extremely complicated record keeping and data collection process to comply with the GHG mandatory reporting program creates undue hardship with minimal value. EPA has offered no scientific reasoning behind their consideration for permitting emergency units and therefore we recommend EPA not proceed with requiring permit for emergency units.

Response: EPA has revised the rule language to remove the prerequisite for a state or local permit. Please refer to the full definitions of emergency generator and emergency equipment in §98.6.

Commenter Name: Paul Dubenetzky
Commenter Affiliation: KERAMIDA Inc.
Document Control Number: EPA-HQ-OAR-2008-0508-0419.1
Comment Excerpt Number: 9

Comment: KERAMIDA supports the exclusion of portable equipment and emergency generators. The definition of "portable" contained at 40 CFR 98.6, 74 FR 16625 is not clear regarding mobile equipment such as forklifts. We believe that mobile equipment should be exempt as not being stationary combustion or portable equipment or both. The rule should be revised to make that clear. KERAMIDA also believes that emergency fire pumps should be included in this exclusion (40 CFR 98.30(b)) because their emissions are small and intermittent similar to emergency generators.

Response: In the final rule, EPA has maintained the exclusion of emergency generators, and has excluded other emergency equipment from reporting. EPA has also revised the rule language to remove the prerequisite for a state or local permit. Please refer to the full definitions of emergency generators, portable equipment, and emergency equipment in §98.6. The phrase "same location" in the definition is intended to mean that the equipment remain "stationary" rather than move from one "location" to another "location" within a "facility." EPA did not find a change in rule language necessary regarding the definition of "portable," and believes that the source category definition, as presented in §98.30, is sufficient.

Commenter Name: Phillip McNeely
Commenter Affiliation: City of Phoenix, AZ
Document Control Number: EPA-HQ-OAR-2008-0508-0374.1
Comment Excerpt Number: 8

Comment: Support the exemption for portable equipment and emergency generators.

Response: EPA appreciates the commenter's support. EPA has maintained the exclusion of emergency generators, and has excluded other emergency equipment from reporting. EPA has also revised the rule language to remove the prerequisite for a state or local permit. Please refer to the full definitions of emergency generator and emergency equipment in §98.6. Portable equipment, as defined in §98.6, is also exempt from reporting.

Commenter Name: Michael W. Stroben
Commenter Affiliation: Duke Energy Corporation
Document Control Number: EPA-HQ-OAR-2008-0508-0407.1
Comment Excerpt Number: 8

Comment: EPA should not require that an emergency generator must be listed as such in a state or local permit to be exempt from reporting. The proposed rule includes a very clear definition of "emergency generator." Requiring a permit for emergency generators will serve no purpose. Permitting requirements vary from state to state, particularly for sources that are not subject to

Title V permitting. If EPA's intent is that emergency generators (as defined in the proposed rule) are not subject to reporting, then forcing a permit condition simply adds an administrative compliance burden.

Response: EPA has revised the rule language to remove the prerequisite for a state or local permit.

Commenter Name: Lloyd Stone
Commenter Affiliation: Westlake Chemical Corporation
Document Control Number: EPA-HQ-OAR-2008-0508-0442.1
Comment Excerpt Number: 8

Comment: Does an incinerator with a waste heat boiler meet the definition of "Stationary fuel combustion source"? That is, does a gaseous incinerator "reduce the volume of waste by removing the combustible matter"?

Response: EPA believes that it is clear in §98.30 of the final that the stationary fuel combustion source category includes both incinerators and boilers, and that an incinerator with a waste heat boiler would meet the definition. However, the commenter should note that hazardous waste incinerators will only be required to report emissions from the combustion of any supplemental fuels for which emission factors are provided, unless CEMS are used. Furthermore, it is EPA's intent that sources allowed to use the Tier 1 and 2 methods, which include smaller combustion devices and should be inclusive of control devices such as thermal oxidizers, will only be required to report emissions from the combustion of fuels for which emission factors are provided. In the Preamble, EPA has explained that "EPA believes that the reporting requirements for Tier 1 and Tier 2 would only require the reporting of GHG emissions from supplementary traditional fossil fuels from devices such as thermal oxidizers, pollution control devices, fume incinerators, burnout furnaces, and other such equipment."

Commenter Name: Kathleen M. Sgamma
Commenter Affiliation: Independent Petroleum Association of Mountain States (IPAMS)
Document Control Number: EPA-HQ-OAR-2008-0508-0521.1
Comment Excerpt Number: 16

Comment: In regard to the definition of emergency generators, IPAMS requests that the specification of hours be removed, as it is not reasonable to limit the number of hours.

Response: In the final rule, EPA has eliminated the 100-hour limitation for emergency generators. Please refer to the full definition of emergency generator in §98.6.

Commenter Name: Angus E. Crane
Commenter Affiliation: North American Insulation Manufacturers Association (NAIMA)
Document Control Number: EPA-HQ-OAR-2008-0508-0537.1
Comment Excerpt Number: 12

Comment: Reporting emissions from portable equipment or generating units is unnecessary. NAIMA members support EPA's position because, in part, it eliminates some of the burden that would be imposed on each facility if it had to report emissions from these types of units. Moreover, EPA's position is consistent with its statement that the "purpose of the general stationary combustion source category is to capture significant emitters of stationary combustion GHG emissions that are not covered by the specific source categories described elsewhere in this preamble." (Id. at 16,482). NAIMA believes that the exemption should be expanded to include all fossil fuel-powered engines that drive emergency pumps, fans, and other devices that are neither generators nor portable. Every industrial manufacturer has such devices on-site. But since fossil fuel-powered engines that drive emergency devices and portable equipment typically operate very few hours in any given year, they discharge a very small amount of GHG. The GHG emissions from these devices are the most difficult to compute, and excluding them will lessen the record keeping and reporting burden with little sacrifice in GHG accounting. Moreover, either excluding all of these emergency or back up devices or including all of these emergency or back up devices would be less burdensome than excluding only some of them. Virtually none of these devices have fuel flow meters or tank gauges that accurately show the amount of fuel used by that individual unit. Instead, facilities rely on plant-wide fuel usage figures and it would lessen their burden if they could either report the GHG that was emitted by all of these engines' fuels or, better yet, just disregard them altogether. Trying to apportion the amount of diesel fuel, for instance, that was used only by those engines that are included in the reporting scheme is much harder than just reporting all of the GHG from all of the engine fuel, or reporting none of the GHG from all of the engine fuel.

Response: EPA has revised several sections of the rule that are relevant. Please refer to the full definitions of emergency generators, portable equipment, and emergency equipment in §98.6. Also, please refer to the revised §98.36(c)(3) which clarifies the methodology for reporting units which are served by a common supply line.

Commenter Name: William C. Herz
Commenter Affiliation: The Fertilizer Institute (TFI)
Document Control Number: EPA-HQ-OAR-2008-0508-0952.1
Comment Excerpt Number: 7

Comment: Under the proposed 40 C.F.R. §98.30(b), EPA would exclude portable equipment or generating units designated as emergency generators in a permit issued by a state or local air pollution control agency. 74 Fed. Reg. 16,631. The proposed rule should exclude all portable equipment, all emergency equipment (such as fire pumps, generating units, flood control pumps, etc.), and any equipment listed as insignificant in a facility permit. In response to EPA's request in the NPRM Preamble, portable equipment and emergency equipment should be excluded regardless of permit designation. 74 Fed. Reg. at 16,461 (FN 31).

Response: EPA has maintained the exclusion of emergency generators, and has excluded other emergency equipment from reporting. EPA has also revised the rule language to remove the prerequisite for a state or local permit. Please refer to the full definitions of emergency generators, portable equipment, and emergency equipment in §98.6.

Commenter Name: Paul Glader
Commenter Affiliation: Hecla Mining Company
Document Control Number: EPA-HQ-OAR-2008-0508-0579.1
Comment Excerpt Number: 12

Comment: Hecla agrees that portable equipment and emergency generators are properly excluded from this rule. Backup generators and portable equipment may vary tremendously in size and are typically seldom used. Requiring reporting on these sources would be unduly burdensome, especially on small businesses. Furthermore, collecting data on these sources would not add significantly to EPA's understanding of the CO_2e emissions produced in the United States.

Response: EPA appreciates the commenter's support. EPA has maintained the exclusion of emergency generators and portable equipment, and has excluded other emergency equipment from reporting. EPA has also revised the rule language to remove the prerequisite for a state or local permit. Please refer to the full definitions of emergency generator, portable equipment, and emergency equipment in §98.6.

Commenter Name: Marc J. Meteyer
Commenter Affiliation: Compressed Gas Association (CGA)
Document Control Number: EPA-HQ-OAR-2008-0508-0981.1
Comment Excerpt Number: 16

Comment: The proposed rule appropriately excludes minor combustion sources from the definition of the Stationary Fuel Combustion source category, in particular process safety flares. CGA supports this effort to minimize the burden on regulated facilities, as these units typically have very low emissions, typically do not have measured flow rates, and do not make a substantial impact on the total greenhouse gas inventory. Flares typically must operate over a widely variable flow rate and it is often very challenging to finding an appropriate flow measurement device capable of covering the range of flows encountered. Any requirement to include these sources would put an unnecessary costly burden on facilities to add flow measurement devices to the feed. As further evidence that these devices should be excluded, thermal oxidizers and air pollution control devices are excluded from greenhouse gas reporting requirements in the European Union. Where flaring operations are a routine operating control of a facility, such as in refineries, EPA has explicitly included emission estimation and reporting requirements. CGA Comment: Clarify that flare emissions should only be included in the calculations of Subpart C of the rule if another subpart of the rule explicitly requires such emission calculation and reporting. Flare emissions should be otherwise excluded categorically or as a de minimis source.

Response: EPA has revised the language of the final rule to expand the list of exempted source categories to exclude flares as defined in §98.6 from reporting under Subpart C, unless their emissions must are required to be reported by another subpart of Part 98 (see §98.30(b)). It is EPA's intent that sources allowed to use the Tier 1 and 2 methods, which include smaller combustion devices and should be inclusive of control devices such as thermal oxidizers, will only be required to report emissions from the combustion of fuels for which emission factors are provided. In the Preamble, EPA has explained that "EPA believes that the reporting requirements for Tier 1 and Tier 2 would only require the reporting of GHG emissions from supplementary traditional fossil fuels from devices such as thermal oxidizers, pollution control devices, fume incinerators, burnout furnaces, and other such equipment." EPA also notes that Subpart W is not being included in this rule at this time.

Commenter Name: Steven M. Pirner
Commenter Affiliation: South Dakota Department of Environment and Natural Resources (SD DENR)
Document Control Number: EPA-HQ-OAR-2008-0508-0576
Comment Excerpt Number: 15

Comment: EPA is not proposing to require reporting of emissions from portable equipment or generating units designated as emergency generators in a permit issued by a state or local air pollution control agency. EPA is requesting comments on "whether or not a permit should be required for theses emergency generators." This is not the correct venue for determining if an emergency generator should be required to be permitted. There are current state and federal requirements already in rule on when emergency generators are permitted. SD DENR agrees with EPA in not requiring facilities to report greenhouse gas emissions from emergency generators because the limited number of hours an emergency generator runs results in insignificant greenhouse gas emissions.

Response: EPA has revised the rule language to remove the prerequisite for a state or local permit for emergency generators. Please refer to the full definitions of portable equipment, emergency generator, and emergency equipment in §98.6.

Commenter Name: Jeffry C. Muffat
Commenter Affiliation: 3M Company
Document Control Number: EPA-HQ-OAR-2008-0508-0793.1
Comment Excerpt Number: 10

Comment: The exemption in Section 98.30(b) is narrow in scope and should be expanded. The explicit designation as an emergency generator in a permit should not be necessary to exclude it from reporting. In addition, air pollution control devices should be exempt from the rule. Some emergency generators might not be designated as "emergency" in their air permits even though they are for emergency use. Furthermore, some may not be permitted at all. How the emissions from these generators are authorized will vary from state to state, depending on the details of state programs. The emissions from emergency generators are very small compared to other stationary fuel combustion sources and are insignificant compared to the inventory of greenhouse gases; therefore, exempting these emissions will not have a significant impact on the usefulness of the greenhouse gas inventory. Additionally, in Section 98.30(b), the term "emergency generators" should be changed to "emergency stationary RICE." Many facilities use combustion units (e.g., diesel engines) as the motive force for pumps, to ensure fire water availability and process fluid movement during power outages. 3M recommends that EPA exclude all emergency stationary reciprocating internal combustion engines (RICE) as the term is defined in 40 CFR 63 Subpart ZZZZ (§63.6675). These are sources whose operation is limited to emergency situations and whose emissions are negligible when compared to other stationary combustion sources. Exclusion of these sources would exclude sources such as stationary RICE used to pump water in the case of fire or flood, for example. In §98.30(b), 3M requests that EPA exclude thermal oxidizers and other air pollution control devices from the definition of stationary combustion sources requiring calculation and reporting of greenhouse gas emissions. These units typically have lower emissions with no substantial impact on the total greenhouse gas inventory and generally would not have measured flow rates. In addition, thermal oxidizers and air pollution control devices are excluded from the greenhouse gas reporting requirements in the European Union. For the reasons provided above, 3M recommends that EPA change Section 98.30(b) to read as follows: (b) This source category does not include portable equipment or units that are emergency stationary reciprocating internal combustion engines. Air pollution control devices such as thermal oxidizers are also exempt from this source category unless another subpart of the rule references an air pollution control device as a greenhouse gas emission source requiring calculation and reporting of emissions.

Response: EPA acknowledges the concerns of the commenter. A number of exemptions to GHG emissions reporting have been added for certain unconventional combustion processes and types of fuel. EPA has maintained the exclusion of emergency generators, and has excluded other emergency equipment from reporting. EPA has also revised the rule language to exclude the prerequisite for a state or local permit. Please refer to the full definitions of portable equipment, emergency generator, and emergency equipment in §98.6. EPA has revised the Preamble and §98.33 to deal with certain unconventional combustion processes and types of fuel. It is EPA's intent that sources allowed to use the Tier 1 and 2 methods, which include smaller combustion devices and should be inclusive of control devices such as thermal oxidizers, will only be required to report emissions from the combustion of fuels for which emission factors are provided. In the Preamble, EPA has explained that "EPA believes that the reporting requirements for Tier 1 and Tier 2 would only require the reporting of GHG emissions from supplementary traditional fossil fuels from devices such as thermal oxidizers, pollution control devices, fume incinerators, burnout furnaces, and other such equipment." EPA believes that these provisions satisfy the intent of Part 98, to collect accurate and consistent GHG emissions data that can be used to inform future decisions.

Commenter Name: Donald R. Schregardus
Commenter Affiliation: Department of the Navy, Department of Defense (DoD)
Document Control Number: EPA-HQ-OAR-2008-0508-0381.1
Comment Excerpt Number: 10

Comment: EPA should expand the emergency generator exemption to cover units that are exempt per state regulations, including "permit-by-rule," allow owners/operators additional hours to be used for maintenance check and readiness testing, and consider other legitimate uses of emergency and back-up power generation in its definition of "emergency generator." DoD agrees with EPA's intent to exempt emergency generators from the GHG mandatory reporting rule, but believes the descriptions provided in the preamble (several footnotes) and in Subparts C and D at §§98.30(b) and 98.40(b) are not adequate to cover all emergency generators. A number of state and local air pollution control agencies exempt emergency generators from certain CAA regulations via "permit-by-rule" rather than a specific permit for the unit or under a General permit. These units should also be exempted from the GHG mandatory reporting rule. With respect to maintenance checks and readiness testing, the January 18, 2008 final rule for Standards of Performance for Stationary Spark Ignition Internal Combustion Engines (ICE) and National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines, EPA recognized that in some cases, 100 hours was not an adequate limit for testing of emergency generators. At §60.4243(d), EPA provided an alternative whereby, "The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that Federal, State, or local standards require maintenance and testing of an emergency ICE beyond 100 hours per year." This allowance would provide DoD and other operators of emergency generators a mechanism to test the emergency units to meet not only manufacturers' requirements but also to meet testing protocols mandated by Federal standards. Lastly, the definition for "emergency generator" does not include applications of these units that are common for DoD, specifically training requirements for military personnel to operate using back-up power in order to be familiar with how their equipment will perform during an emergency. These applications also do not fit within the 100 hour per year "standard performance testing" allowed in the definition. EPA should modify the definition for emergency generator and the exemptions for emergency generators in §§98.30(b) and 98.40(b). Suggested language revisions: "§98.6 - Emergency generator means a stationary internal combustion engine that serves solely as a secondary source of mechanical or electrical power whenever the primary energy supply is disrupted or discontinued during power outages or natural disasters that are beyond the control of the owner or operator of a facility. Emergency engines operate only during emergency situations, for training of personnel under simulated emergency conditions, and for standard performance testing procedures as required by law or by the engine manufacturer. The hours of operation per calendar year for such standard performance testing shall not exceed 100 hours. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that Federal, State, or local standards require maintenance and testing of an emergency ICE beyond 100 hours per year. An engine that serves as a back-up power source under conditions of load shedding, peak shaving, power interruptions pursuant to an interruptible power service agreement, or scheduled facility maintenance shall not be considered an emergency engine." "§98.30 Definition of the source category. (b) This source category does not include portable equipment or generating units designated as emergency generators in a permit issued by a state or local air pollution control agency, exempt from state permitting requirements, or via 'permit by rule.'" "§98.40 Definition of the source category. (b) This source category does not include portable equipment or generating units designated as emergency generators in a permit issued by a State or local air pollution control agency, exempt from state permitting requirements, or via 'permit by rule.'"

Response: EPA has maintained the exclusion of emergency generators, although it has eliminated the 100-hour limitation for emergency generators, and has excluded other emergency equipment from reporting. EPA has also revised the rule language to exclude the prerequisite for a state or local permit. Please refer to the full definition of emergency generator in §98.6.

Commenter Name: Lawrence W. Kavanagh
Commenter Affiliation: American Iron and Steel Institute (AISI)
Document Control Number: EPA-HQ-OAR-2008-0508-0695.1
Comment Excerpt Number: 17

Comment: If reporting of combustion source CO_2 emissions is retained in the final rule, and if EPA is unwilling to consider our proposed facility-wide carbon balance approach, which would cover emissions from all combustion units less than 250 MMBTUH, we respectfully request that units less than 250 MMBTUH be exempt from reporting. In the alternative, a de minimis threshold, e.g., the 30 MMBTUH exemption rate corresponding to the exemption threshold of 25,000 metric tons of CO_2/year, should be established.

Response: See the Preamble, Section II. E., and the response to comment EPA-HQ-OAR-2008-0508-0350.1 excerpt 3 for additional explanation of the selection and form of thresholds.

See the Preamble, Section II. K., and the response to comment EPA-HQ-OAR-2008-0508-0423.2 excerpt 40 for the response on de minimis reporting for small emission points.

EPA has expanded the list of exempted source categories to include portable equipment, emergency generators, other emergency equipment, irrigation well devices, and flares. EPA has also removed the cumulative 250 mmBtu/hr restriction on unit aggregation, and believes that the expanded availability of this option will reduce the reporting burden on facilities.

While units less than 250 mmBtu/hr are not exempt from reporting under Subpart C, they are typically permitted to use Tiers 1 and 2 for reporting, which should reduce the burden on facilities.

Commenter Name: See Table 9
Commenter Affiliation:
Document Control Number: EPA-HQ-OAR-2008-0508-1021.1
Comment Excerpt Number: 7

Comment: EPA should clarify its exemption from reporting for emergency generators and similar equipment (e.g., emergency diesel fire pumps) under the proposed rule to acknowledge that not all states issue permits for this equipment. Because some of these generators and related equipment are too small to either require a permit or be covered in existing permits, a permit should not be required for the exemption under this rule.

Response: EPA has maintained the exclusion of emergency generators, and has excluded other emergency equipment from reporting. EPA has also revised the rule language to exclude the prerequisite for a state or local permit. Please refer to the full definitions of emergency generator and emergency equipment in §98.6.

Commenter Name: Robert Rouse
Commenter Affiliation: The Dow Chemical Company
Document Control Number: EPA-HQ-OAR-2008-0508-0533.1
Comment Excerpt Number: 20

Comment: Dow Suggests that Emergency Generators and Emergency Stationary Engines Should Not be Included in the Source Category. EPA requests comment on whether a permit should be required for emergency generators that are excluded from GHG reporting requirements in 98.30(b). Dow agrees with EPA that the reporting of GHG emissions from emergency generators is not necessary. This is supported by their infrequent use and resulting relatively small contribution to the total GHG inventory. Excluding these emissions will not have a significant impact on the usefulness of the GHG inventory. In 98.30(b), Dow does not believe that designation as an emergency generator in a permit should be necessary to exclude them from reporting. Some emergency generators might not be designated as "emergency" in their air permit even though they are for emergency use. Further, the "authorization" or "permitting" of emissions from these generators varies from state to state, depending on the details of state NSR permitting programs. For example, the Texas NSR permitting program allows either the permitting of these sources and also authorizes these sources using a Permit by Rule. Dow suggests that an internal record that identifies these sources as an "emergency generator" should be sufficient to properly identify these sources as such. In addition, in 98.30(b), the term "emergency generators" should be expanded to "emergency generators and engines." Dow suggests that EPA exclude all emergency stationary reciprocating internal combustion engines (RICE) as the term is defined in 40 CFR 63 Subpart ZZZZ (63.6675). These are sources whose operation is limited to emergency situations whose emissions are negligible when compared to other stationary combustion sources. Exclusion of these sources would exclude sources such as stationary RICE used to pump water in the case of fire or flood, for example. Dow Suggests that EPA Should Clarify the Applicability of Subpart C for Emission Control Equipment Such as Flares, Thermal Oxidizers, and Other Air Pollution Control Devices. At a minimum, EPA should clarify that flare/emission control device emissions should be included in the calculations of Subpart C of the rule if another subpart of the rule references "flares" or "emission control" equipment as a GHG emission source requiring calculation and reporting of emissions. Examples include Subpart X (Petrochemical Facilities) and Subpart Y (Petroleum Refineries). The final rule should clarify the requirements for flares and emission control equipment that combust emissions from other source categories that are not specifically addressed in the proposed rule. Dow suggests that EPA include the emissions from these sources if they exceed 1,250 metric tons of CO_2e, which is 5% of the 25,000 metric ton reporting trigger. This approach would ensure the reporting of larger emitting flares/control equipment while excluding sources that may only handle intermittent types of vents. Dow Suggests that EPA Should Clarify the Applicability of Subpart C for Facilities that Combust Hazardous Waste. It is not clear whether EPA intended for facilities to report GHG emissions of hazardous waste burned in hazardous waste incinerators or combustors. For example, Table C-1 on page 16481 of the Federal Register does not mention hazardous waste fuels. Dow recommends that EPA exempt hazardous waste combustion units from the rule. These units would be relatively small contributions to the total inventory and may vary widely in flow rate and composition, thus making the calculations more difficult. Furthermore, EPA has recognized the relatively small contribution by exempting hazardous waste from the calculations and reporting in the landfill subpart of this proposed rule.

Response: See the Preamble and separate comment response document volume for the response on de minimis reporting for small emission points.

EPA has maintained the exclusion of emergency generators and has excluded other emergency equipment from reporting. EPA has also revised the rule language to exclude the prerequisite for a state or local permit. Please refer to the full definitions of emergency generator and emergency equipment in §98.6.

EPA has expanded the list of exemptions from the stationary combustion source category in §98.30(b) to include flares, except where another subpart requires flare emissions to be reported.

Emissions from hazardous waste incinerators need not be reported unless CEMS are used to monitor emissions or a fuel for which emission factors are provided is also combusted in the unit. In that case, only emissions from the supplemental fuel need to be reported.
EPA has revised the Preamble and §98.33 to deal with certain unconventional combustion processes and types of fuel. It is EPA's intent that sources allowed to use the Tier 1 and 2 methods, which include smaller combustion devices and should be inclusive of control devices such as thermal oxidizers, will only be required to report emissions from the combustion of fuels for which emission factors are provided. In the Preamble, EPA has explained that "EPA believes that the reporting requirements for Tier 1 and Tier 2 would only require the reporting of GHG emissions from supplementary traditional fossil fuels from devices such as thermal oxidizers, pollution control devices, fume incinerators, burnout furnaces, and other such equipment." EPA believes that these provisions satisfy the intent of Part 98, to collect accurate and consistent GHG emissions data that can be used to inform future decisions.

Commenter Name: Ron Downey
Commenter Affiliation: LWB Refractories
Document Control Number: EPA-HQ-OAR-2008-0508-0719.1
Comment Excerpt Number: 6

Comment: Preamble C., p 173-174. EPA's asked for comments regarding portable equipment. We agree with EPA's proposal not to require reporting of portable equipment or generating units designated as emergency generators in a permit issued by a state.

Response: EPA appreciates the commenter's support. EPA has maintained the exclusion of emergency generators, and has excluded other emergency equipment from reporting. EPA has also revised the rule language to exclude the prerequisite for a state or local permit. Please refer to the full definitions of emergency generator and emergency equipment in §98.6. Portable equipment, as defined in §98.6, is also exempt from reporting.

Commenter Name: Donald R. Schregardus
Commenter Affiliation: Department of the Navy, Department of Defense (DoD)
Document Control Number: EPA-HQ-OAR-2008-0508-0381.1
Comment Excerpt Number: 5

Comment: Many complex facilities that will be subject to the reporting rule under §98.2(a)(1), (a)(2), or(a)(3) will be required to inventory a large number of small combustion units covered by the rule. We believe a size threshold is needed in the stationary combustion source category to reduce undue cost burden while still achieving EPA's goal of obtaining GHG data of sufficient quality that it can be used to support a range of future climate change policies and regulations. With the goal of focusing this rulemaking on large GHG emitters, EPA writes that it is able to minimize the cost burden of the rule while still gathering GHG data in sufficient detail to advise future policy decisions. However, an unnecessary burden will be placed on reporting sources if the combustion unit source category does not have minimum size threshold added to the source category definition. In the Memorandum: Reporting Methods for Small Emission Points (De Minimis Reporting), EPA discusses the possibility of a de minimis provision to avoid imposing excessive reporting costs on minor emission points that can be burdensome or infeasible to monitor. EPA analyzed the de minimis provisions of existing reporting rules and concluded that there is no need to exclude a percentage of emissions from reporting under this proposal. EPA explains that it attempts to avoid burdening smaller sources in the way it sets thresholds and providing simplified emission estimation methods such as the application of Tiers 1 and 2 for small units. However, this approach will not provide relief to complex sources. As EPA determined during the development of the Title V, Operating Permit Program, there was a need to provide exemptions for insignificant activities or emission levels. This is incorporated in 40 CFR §70.5(c). The Title V regulation limits the State's discretion by precluding such exemptions if they would interfere with the determination or imposition of any applicable requirement. Permit applications are to include lists containing information on the insignificant activities that are exempted except for those exemptions which apply to an entire category of activities, such as space heaters. As supported by the Alabama Power decision, the Administrator may determine levels below which there is no practical value in conducting an extensive review. States such as Oregon (at OAR-340-200-0020) have taken the approach of developing a 'categorically insignificant activity' with heat capacity limits for liquid and gaseous-fueled units. The Technical Support Document (TSD) for "Stationary Fuel Combustion Emissions" and "Technical Support Thresholds: Proposed Rule for Mandatory Reporting of Greenhouse Gases" both show that commercial and residential sectors emitted about 14 percent of U.S. GHG emissions from stationary fuel combustion. In Table 5-5, which lists industrial and commercial boiler population in the U.S., boilers less than 10 MMBtu/hr are not tabulated, suggesting they do not belong in this source category. The commercial sector includes emissions from fuel combustion in commercial and institutional buildings (space heating and cooling, water heating, cooking and baking, and dryers). The residential sector includes emissions from household fuel combustion (space heating, water heating, and cooking). The Regulatory Impact Analysis, at page 27, explains the high cost and burden that would be incurred if the rule covered the commercial and residential sectors. To avoid this impact, the proposed rule does not include all of those emitters, but instead requires reporting by the suppliers of industrial gases and suppliers of fossil fuels. In Subpart C - General Stationary Fuel Combustion Sources - the definition of "stationary fuel combustion sources" at §98.30(a) appears to capture all heaters of any size or purpose, used for industrial, commercial, or institutional purposes. This definition lists every 'level' of fuel combustion source except for residential units but there is no language specifically excluding residential units. There are also no definitions of commercial or residential units in the proposal. Although §98.36(c)(1) allows for aggregation of units for reporting of emissions from this source category, the facility would still be required by the proposed language in §98.36(c)(1)(ii) to identify each unit, no matter how small, and provide a unit ID Number. Requiring a listing of individual units that are not intended to be covered by the rule is a burdensome and un-necessary collection of data, as it is not clear what use the EPA intends for the detailed data on small aggregated stationary fuel combustion sources that would be gathered under this proposed reporting requirement. These simplifications provided in Subpart C do not provide relief to facilities that operate small combustion sources that have insignificant impact on emission totals such as office building or control room comfort heating, cafeteria operations or heated lockers that are located on the footprint of the industrial activity. We recommend to EPA to align the source definition in Subpart C to match the intent of the rule to focus on large emitters and to clarify the sources subject to the rule. Include definitions for commercial and residential fuel combustion sources. Specifically exclude residential units from the source category. Set a capacity threshold for commercial-size units that are excluded from the source category.

Response: See the Preamble and separate comment response document volume for the response on de minimis reporting for small emission points. See the response to comment EPA-HQ-OAR-2008-0508-0615 excerpt 21 for an explanation of the treatment of residential facilities.

EPA acknowledges the commenter's concerns and has expanded the list of combustion sources and fuels that are exempted from reporting. Please refer to §98.6 for revised definitions of portable equipment, emergency generators, other emergency equipment that are exempted. The revised source category definition also exempts irrigation well devices and flares, except where covered by other parts of the rule. In addition, EPA has also removed the cumulative 250 mmBtu/hr restriction on unit aggregation and clarified the use of common supply line metering, and believes that the expanded availability of this option will reduce the reporting burden on facilities. However, EPA does not agree with the commenter's assertion that the amount of unit-level data and verification information to be reported is excessive, burdensome, or unnecessary. For this mandatory GHG emissions reporting rule, two main approaches to data verification were considered, i.e., EPA verification and third-party verification. EPA decided on the former approach. In view of this, additional, unit-level information, including ID numbers for units grouped in common pipe or common stack configurations and included in unit aggregation, is deemed necessary to provide assurance that the reported facility-wide GHG emissions data are both credible and accurate.

Commenter Name: Ron Downey
Commenter Affiliation: LWB Refractories
Document Control Number: EPA-HQ-OAR-2008-0508-0719.1
Comment Excerpt Number: 5

Comment: Preamble C., p 172 and Subpart C, 98.30 (a). The definition of stationary fuel combustion source category includes but is not limited to among other sources incinerators. Incinerators are not clearly defined as we could determine. The reporting requirements are different depending on the TIER selected for reporting. One definition of incinerator would include waste combustors such as municipal waste or other units that reduce the volume of waste such s a municipal waste incinerator. Does this incinerator definition include hydrocarbon pollution control devices such as a thermal incinerator, catalytic incinerator or regenerative thermal oxidizers that are required to meet permitted emissions limits? We have several sources that are combustion sources (ovens, kilns) that have an incinerator to control organic emissions. In this case does the incinerator (control device) meet the definition of a stationary fuel combustion source and require emission reporting? Several different issues are involved. A gas or oil fired kiln would meet the reporting criteria? Does the fuel required to fire the incinerator meet the reporting criteria? Does any GHG from the hydrocarbon emissions from the organic binder meet the reporting criteria? Again this may be dependent on the TIER selected for reporting. In many cases these sources are small and would not justify the purchase of a CO_2 CEM for recording GHG emissions.

Response: It is EPA's intent that sources allowed to use the Tier 1 and 2 methods, which include smaller combustion devices and should be inclusive of control devices such as thermal oxidizers, will only be required to report emissions from the combustion of fuels for which emission factors are provided. In the Preamble, EPA has explained that "EPA believes that the reporting requirements for Tier 1 and Tier 2 would only require the reporting of GHG emissions from supplementary traditional fossil fuels from devices such as thermal oxidizers, pollution control devices, fume incinerators, burnout furnaces, and other such equipment." The Agency believes that these provisions satisfy the intent of Part 98, to collect accurate and consistent GHG emissions data that can be used to inform future decisions. The commenter is encouraged to consider the complete definitions provided in the revised §98.6.

Commenter Name: Edgar O. Morris
Commenter Affiliation: Mosaic Fertilizer Company LLC
Document Control Number: EPA-HQ-OAR-2008-0508-0687.1
Comment Excerpt Number: 5

Comment: The proposal properly excludes portable equipment and certain emergency equipment from its definition of stationary fuel combustion sources subject to GHG reporting. See proposed 40 C.F.R. §98.30(b). However, this definition should be clarified to cover other emergency equipment in addition to "portable equipment or generating units designated as emergency generators" and should cover all portable and emergency equipment, regardless of whether they are so designated on a permit. Additional emergency equipment would include such things as fire protection pumps and flood control pumps. These types of equipment are equivalent to emergency generators in that they are only utilized in response to abnormal emergency conditions necessary for protection of life and property. This definition should also exclude any equipment associated with insignificant emissions and therefore not regulated or subject to other reporting requirements in an air permit. For all of these sources the same rationale applies: Reporting GHG emissions from these minor sources imposes a reporting burden on companies and provides only immaterial GHG emissions information to EPA. Mosaic proposes the following clarifying revision: §98.30 Definition of the source category (b) This source category does not include portable equipment or equipment designated as "emergency" equipment, or sources designated as "insignificant" in a permit issued by a state or local air pollution control agency.

Response: EPA has maintained the exclusion of emergency generators, and has excluded other emergency equipment from reporting. EPA has also revised the rule language to remove the

prerequisite for a state or local permit. Please refer to the full definitions of portable equipment, emergency generators, and emergency equipment in the revised §98.6.

Commenter Name: Lawrence W. Kavanagh
Commenter Affiliation: American Iron and Steel Institute (AISI)
Document Control Number: EPA-HQ-OAR-2008-0508-0695.1
Comment Excerpt Number: 4

Comment: Cokemaking operations, whether contained within integrated steel plants or operated as stand-alone facilities, are obligated under the proposed rule to report emissions from combustion stacks under terms of Subpart C and from pushing operations using an emission factor provided in Subpart Q. Many coke plants also have boilers or other combustion sources that would be subject to reporting under Subpart C. In the first instance, any CO_2 emitted from coke oven combustion stacks will have already been accounted for by reports of coal suppliers under Subpart KK. Thus, reporting of CO_2 from combustion of coke oven gas for underfiring ovens or other combustion sources is duplicative. Furthermore, requirements for reporting these emissions is inconsistent with the stated intention of the rule – as well as underlying intent of the Congressional mandate – to require reporting of upstream sources to the maximum extent possible. For this reason, AISI and ACCCI strongly urge EPA to delete coke oven combustion stack CO_2 reporting from the rule.

Response: See the Preamble for the response on the statutory authority for the reporting rule and separate comment response document volume for the response on definition of the source category.

EPA intends that the stationary combustion source category include any device that meets the definition included in §98.30 for which emissions are not accounted for in the report through a separate subpart of the rule. Per the requirements in 40 CFR Part 98, Subpart A, facilities have to report GHG emissions from all source categories located at their facility, including stationary combustion and process emissions. EPA has revised the various subparts of the final rule to clarify the intent of the stationary combustion source category.

The commenter should note that EPA is not preparing a final version of the subpart for suppliers of coal at this time. The commenter should also note that EPA was asked to collect data from both upstream and downstream sources. The calculation methods for downstream reporters are based on collecting the best information from downstream emitters. See the Preamble, Section II. D. 3., for the response to comments on the inclusion of upstream and downstream reporters.

Commenter Name: Jay M. Dietrich
Commenter Affiliation: IBM
Document Control Number: EPA-HQ-OAR-2008-0508-0978.1
Comment Excerpt Number: 4

Comment: Inclusion of Emergency Generator Fuel Use in Emissions Reports IBM agrees with EPA that it is not necessary to include the fuel use from permitted Emergency Generating units.

These units are typically restricted to less than 500 hours of operation per year and, using IBM's facilities as an example, represent less than 0.1% of the fuel use at the facilities that would be covered by the proposed reporting thresholds. On page 16480 of the Federal Register rule, EPA states "We request comment on whether or not a permit should be required for these emergency generators." Permits, beyond the current operating permits for these systems, should not be required nor should the permit requirements be modified to include language for the management of CO_2 emissions

Response: EPA has maintained the exclusion of emergency generators, and has excluded other emergency equipment from reporting. EPA has also revised the rule language to remove the prerequisite for a state or local permit. Please refer to the full definitions of emergency generator and emergency equipment in §98.6.

Commenter Name: Jessica S. Steinhilber
Commenter Affiliation: Airports Council International North America (ACI-NA)
Document Control Number: EPA-HQ-OAR-2008-0508-1063.1
Comment Excerpt Number: 9

Comment: EPA states that generator usage for "scheduled facility maintenance shall not be considered an emergency engine." Many facilities occasionally rely on generators during de-electrification of a system for a high-power replacement of electric switching or required maintenance of such a high-voltage system. ACI-NA suggests that such generator use falls within the definition of "emergency generator" when the total hours used, including generator standard performance testing, do not exceed 200 hours per calendar year. While EPA proposes a usage threshold of 100 hours per calendar year, there is existing precedent for relying on 200 hours. As one example, California's South Coast Air Quality Management District Rule 1304 (a)(4) defines "Emergency Equipment" as a "source [that] is exclusively used as emergency standby equipment for nonutility electrical power generation or any other emergency equipment as approved by the Executive Officer or designee, provided the source does not operate more than 200 hours per year as evidenced by an engine-hour meter or equivalent method." This situation happens very infrequently, but is necessary to keep electric systems that are crucial to safe and essential airport operations running at optimum efficiency.

Response: EPA has revised the final rule to eliminate the 100-hour limitation for emergency generators. Please refer to the full definitions of emergency generator and emergency equipment in §98.6.

Commenter Name: Lauren E. Freeman
Commenter Affiliation: Hunton & Williams LLP
Document Control Number: EPA-HQ-OAR-2008-0508-0493.1
Comment Excerpt Number: 24

Comment: Under Subpart C, the term "stationary fuel combustion sources" is defined simply as a device that combusts fuel. Proposed §98.30(a). Although the rule describes some of the general uses of these devices, it does not require that the device be used for any particular purpose. UARG is concerned that miscellaneous combustion sources, like small gas-fired heaters, stoves, or even hot water heaters, at electric generating facilities could be construed as falling under that broad description. Reporting GHG emissions from such miscellaneous devices could be very difficult even using the Tier 1 methodology because specific data on fuel consumption might not be available. To avoid requiring reporting from such activities, UARG request that EPA either provide a more specific definition of combustion device or include a de minimis cut-off.

Response: See the Preamble and separate comment response document volume for the response on de minimis reporting for small emission points. In addition, EPA has also removed the cumulative 250 mmBtu/hr restriction on unit aggregation and clarified the use of common supply line metering, and believes that the expanded availability of this option will reduce the reporting burden on facilities, particularly for including smaller combustion sources.

EPA appreciates the commenter's concern, and believes that the revised §98.30 appropriately defines the general stationary combustion source category.

Commenter Name: Karen St. John
Commenter Affiliation: BP America Inc. (BP)
Document Control Number: EPA-HQ-OAR-2008-0508-0631.1
Comment Excerpt Number: 55

Comment: "EPA is proposing to not require reporting of emissions from portable equipment or generating units designated as emergency generators in a permit issued by a state or local air pollution control agency. We request comment on whether or not a permit should be required for these emergency generators." (p. 16480) BP supports EPA's approach of not requiring emissions reporting from emergency equipment or portable equipment. BP recommends that EPA extend the scope of this exclusion to include all emergency equipment (not just generators) such as fire-water pumps, life boats, etc along with portable equipment. BP does not believe that designation as an emergency unit in a permit should be necessary to exclude emergency equipment from reporting. Some emergency equipment may not be designated as "emergency" in their air permit even though they are for emergency use. Further, some may not be permitted at all. How the emissions from these emergency units are authorized will vary from state to state and jurisdiction to jurisdiction, depending on the details of the programs. For example, due to the MMS jurisdiction in Federal waters there is no permit program and no opportunity to establish a permit designation; Indiana does not permit emergency generators at all, but rather considers them to be de minimis; Texas might cover them under a PBR (Permit by Rule). In §98.30(b), the term "emergency generators" should be changed to "emergency generators, pumps, lifeboats, and other emergency equipment." Many facilities use combustion units (e.g., diesel engines) as the motive force for emergency pumps, to ensure fire water availability and process fluid movement during power outages and life boats are powered with liquid fuels. BP further recommends that EPA exclude all emergency stationary reciprocating internal combustion engines (RICE) as the term is defined in 40 CFR 63 Subpart ZZZZ (§63.6675). These are sources whose operation is limited to emergency situations and whose emissions are negligible when compared to other stationary combustion sources. Exclusion of these sources would exclude sources such as stationary RICE used to pump water in the case of fire or flood, for example. EPA should also consider exclusion of infrequent use stationary units (such as small generators) which are used during maintenance activities for control and minor power uses. EPA should specifically acknowledge that portable onshore drilling and completion rigs and mobile offshore drilling units (regardless of time at the same lease block or coordinates) (vessels) are "portable sources" and excluded for rule applicability.

Response: Because of the need for comprehensive, national greenhouse gas emissions data, the final rule provides only limited exclusions from the reporting requirements. In the final rule EPA has maintained the exclusion of emergency generators and portable equipment, has removed the requirement for a state or local permit designating them as emergency generators, and has excluded other emergency equipment from reporting. See §98.6, which includes definitions of emergency generator and emergency equipment. However, stationary units used during scheduled or routine maintenance are not emergency equipment and are not excluded. This is because maintenance operations are not necessarily infrequent, the equipment involved can be of widely varying sizes, and consequently the GHG emissions from these operations cannot be assumed to be, and treated as, insignificant. With regard to the application of the portable equipment exclusion to equipment on onshore drilling and completion rigs and on offshore drilling units, the exclusion covers only equipment that is portable, as defined in the rule. Under the definition of "portable," equipment that is "designed and capable of being carried or moved from one location to another" is portable, unless such equipment meets one or more certain specified criteria related to ability to be moved and residency time at a particular location within a facility. The commenter does not provide any basis for changing the definition and instead requests that EPA state that equipment on onshore drilling and completion rigs and on offshore drilling units is, under all circumstances, portable, but such a statement would be inconsistent with the definition of "portable." The applicability of the "portable" definition, and thus of the reporting requirements, to particular equipment on a particular onshore rig or offshore unit will depend on the specific circumstances of such rig or unit. Currently lacking such information about the rigs and units, EPA cannot make a determination at this time with regard to the commenter's equipment, but intends to do so in the future, upon request, when such information is provided.

Commenter Name: Rich Raiders
Commenter Affiliation: Arkema Inc.
Document Control Number: EPA-HQ-OAR-2008-0508-0511.1
Comment Excerpt Number: 50

Comment: EPA has long recognized that hazardous waste combustors as the most highly regulated units under the Clean Air Act. Because of the nature of the materials that these combustors process, EPA has appropriately promulgated extensive operating and monitoring requirements to minimize public risk from waste management operations, where EPA has a vested interest in protecting the public from undue risks from hazardous waste activities. Because of this appropriate scrutiny, reporters operating hazardous waste combustion ("HWC") MACT (40 CFR 63 Subpart EEE) units are required to collect extensive quantities of information concerning the streams being combusted in each affected source. Regulated facilities are required to develop detailed waste profiles, describing the composition of the significant components of each stream, the BTU value of each stream, and the firing schedule for each processed waste, for each waste stream introduced into the combustion unit. This compendium of information constitutes a very detailed process knowledge base whereby operators of HWC MACT units can identify, in significant detail with reasonable accuracy, the GHG emissions being emitted from each hazardous waste combustor. 40 CFR 63 Subpart EEE contains extensive instrument monitoring and management provisions that represent the state of the art in parametric monitoring systems. The HWC MACT also requires operators to test each affected source twice every five years for a variety of emissions, including CO_2 emissions by EPA Method 3 (40 CFR 60, Appendix A). The HWC MACT periodic testing requirements, the most extensive testing requirements in all EPA compliance programs, protect the environment and provide adequate data for any reporting system that may be required, including proposed Part 98. HWC MACT operators must also manage the heat value of streams entering the combustor unit. For example, in one Arkema HWC MACT unit, heat values for one stream are determined per batch of material charged to the combustor, and on a periodic basis for a second stream. The facility has the ability to directly evaluate if each stream contributes comparable heat value, as defined by the comparable fuels rule, to the combustion device. These monitoring activities provide data on indicator parameters, a subset of the extensive list of potential analytes that indicate how the stream will perform in the combustor. Supplemental fuel (typically natural gas) is metered using typical natural gas flow meters. As this facility can determine the total fuel loading and heat value by existing systems, no further evaluation of the heating value of the materials combusted should be required. Streams not contributing significant heat value should not be tracked for Part 98 compliance. Part 98 should recognize the existing regulatory scrutiny already placed on HWC MACT operators, and should only require a facility complying with the HWC MACT to use existing data to calculate annual actual GHG emissions. Part 98 should exclude all data management, equipment calibration, and parametric monitoring conditions for any unit complying with 40 CFR 63 Subpart EEE. Compliance with the HWC MACT should be deemed compliance with Part 98, except for the end-of-year actual GHG emission calculation based on existing compliance data. EPA should further note in the preamble of any final Part 98 rule that the existing Method 3 CO_2 determinations from HWC MACT comprehensive performance tests ("CPT") comprise adequate data to derive a site-specific emission CO_2 emission factor with no further testing required.

Response: See the General Stationary Combustion source category section of the Preamble and the separate source category comment response document for the response on the definition of the source category.

EPA acknowledges the concerns of the commenter. Section 98.30 of the final rule clarifies the definition of the general stationary fuel combustion source category and provides an expanded list of sources exempted from GHG emissions reporting under Subpart C. Subsection (c) states that, "For a unit that combusts hazardous waste, . . . reporting of GHG emissions is not required unless: (1) Continuous emission monitors (CEMS) are used to quantify CO_2 mass emissions; or (2) Any fuel listed in Table C-1 of this subpart is also combusted in the unit. In this case, reporting of the GHG emissions from combustion of the other fuel(s), i.e., the fuel(s) listed in Table C-1, is required." If reporting of GHG emissions is required, there is no requirement to derive a site-specific emission factor for CO_2, and the default factors used in Table C-1 can be used. For this reason, the concern raised about the burden or inclusion of hazardous waste combustion is addressed without the specific change requested by the commenter.

Commenter Name: See Table 6
Commenter Affiliation:
Document Control Number: EPA-HQ-OAR-2008-0508-0679.1
Comment Excerpt Number: 48

Comment: EPA is proposing to not require reporting of emissions from portable equipment or generating units designated as emergency generators in a permit issued by a state or local air pollution control agency. We request comment on whether or not a permit should be required for these emergency generators." (p. 16480) API supports EPA's approach of not requiring emissions reporting from emergency equipment or portable equipment. The scope of this exclusion should be broadened to include all emergency equipment (not just generators) such as fire-water pumps, life boats, etc. API does not believe that designation as an emergency unit in a permit should be necessary to exclude emergency equipment from reporting. Some emergency equipment may not be designated as "emergency" in their air permit even though they are for emergency use. Further, some may not be permitted at all. How the emissions from these emergency units are authorized will vary from state to state and jurisdiction to jurisdiction, depending on the details of the programs. For example, due to the MMS jurisdiction in Federal waters there is no permit program and no opportunity to establish a permit designation; Indiana does not permit emergency generators at all, but rather considers them to be de minimis; Texas might cover them under a PBR (Permit by Rule). EPA should allow additional alternatives for omitting reporting for an emergency unit other than description in an air permit, such as type of use. The emissions from emergency units are very small compared to other stationary fuel combustion sources, and are insignificant compared to the inventory of greenhouse gases; therefore, discounting these emissions will not have a significant impact on the usefulness of the greenhouse gas inventory. Also in §98.30(b), the term "emergency generators" should be changed to "emergency generators, pumps, lifeboats, and other emergency equipment." Many facilities use combustion units (e.g., diesel engines) as the motive force for emergency pumps, to ensure fire water availability and process fluid movement during power outages and life boats are powered with liquid fuels. API further recommends that EPA exclude all emergency stationary reciprocating internal combustion engines (RICE) as the term is defined in 40 CFR 63 Subpart ZZZZ (§63.6675). These are sources whose operation is limited to emergency situations and whose emissions are negligible when compared to other stationary combustion sources. Exclusion of these sources would exclude sources such as stationary RICE used to pump water in the case of fire or flood, for example. EPA should exclude infrequent use units (such as small stationary engines) in the same manner in which they have excluded portable equipment which are used during maintenance activities for control and minor power uses. EPA should specifically acknowledge that portable onshore drilling and completion rigs and mobile offshore drilling units (vessels) are "portable sources", regardless of time at the same lease block or coordinates, and excluded for rule applicability.

Response: EPA has maintained the exclusion of emergency generators, and has excluded other emergency equipment from reporting. EPA has also revised the rule language to remove the prerequisite for a state or local permit. Please refer to the full definitions of portable equipment, emergency generators, and emergency equipment in §98.6. The definition of emergency generator includes emergency recipriocating internal combustion engines or turbines. The commenter should note that generators and other equipment used during scheduled facility maintenance are not considered emergency equipment.

Commenter Name: Karen St. John
Commenter Affiliation: BP America Inc. (BP)
Document Control Number: EPA-HQ-OAR-2008-0508-0631.1
Comment Excerpt Number: 46

Comment: Heating value §98.6 (p. 16622): The use of the API compendium would be clearer. Suggested definition is: "Heating Value: The amount of energy released when a fuel is burned completely. (See also HHV and LHV). HHV: Higher Heating Value or Gross Calorific Value. The quantity of heat produced by the complete combustion of a unit volume or weight of fuel assuming that the produced water is completely condensed (liquid state) and the heat is recovered. LHV: Lower Heating Value or Net Calorific Value. The quantity of heat produced by the complete combustion of a unit volume or weight of fuel assuming that the produced water remains as a vapor and the heat of the vapor is not recovered. The difference between the HHV and LHV is the latent heat of vaporization of the product water (i.e., the LHV is reduced by the enthalpy needed to vaporize liquid water).

Response: The commenter did not identify how the EPA definition of HHV was unclear and, therefore, it is difficult to respond to the request to change the definition. EPA believes that the proposed definition of high heat value includes the concepts identified by the commenter and has finalized this definition.

Commener Name: Gregory A. Wilkins
Commenter Affiliation: Marathon Oil Corporation
Document Control Number: EPA-HQ-OAR-2008-0508-0712.1
Comment Excerpt Number: 45

Comment: Marathon proposes exempting emissions from any portable equipment (compressors, generators, welders, etc.), stationary engines (that do not burn refinery fuel gas or natural gas), or emergency equipment. EPA currently proposes to not require reporting of emissions from emergency generating units but EPA should further that exemption to include all emergency equipment including fire water pump drivers. Additionally, Marathon would like to propose that in order to use this exemption, the emergency equipment should not be required to be listed in a permit, and instead equipment be excluded if they are designated by the facility for emergency use. Also, as an example, any equipment exempted from a Title V permit or any de minimis activities as identified in a Title V permit or program should be exempted. These sources are not only small and insignificant to the overall emissions data but are also extremely difficult to estimate due to their mobility and the number of units. Another problem is that many are used by contractors and are difficult to track. Also, the fuel used in this equipment (engines, portable equipment, etc.) is already being counted as product emissions from the facility where the fuel was produced. This would result in double counting. It is onerous to track fuel used for small portable, stationary, or emergency equipment for insignificant emissions and should be exempted or allowed to be accounted for as a portion of the de minimis level.

Response: See the Preamble and separate comment response document volume for the response on de minimis reporting for small emission points.

EPA has expanded the list of exempted source categories to include portable equipment, emergency generators, other emergency equipment, irrigation well devices, and flares except where required in other subparts of the rule. EPA has revised the rule language to remove the prerequisite of a state or local permit for the exclusion of an emergency generator. Please refer to the full definitions of emergency generator, emergency equipment, and portable equipment in §98.6. In addition, EPA has revised the rule in order to ease the reporting burden on facilities, such as allowing the use of a common supply line to determine fuel combustion, and removing the cumulative 250 mmBtu/hr restriction on unit aggregation.

The commenter should note that EPA was asked to collect data from both upstream and downstream reporters. The calculation methods for downstream reporters are based on collecting the best information from downstream emitters.

Commenter Name: Michael Carlson
Commenter Affiliation: MEC Environmental Consulting
Document Control Number: EPA-HQ-OAR-2008-0508-0615
Comment Excerpt Number: 16

Comment: We recommend that the exemption for reporting of GHG emissions from emergency generators not be limited to those generators which are permitted by either the state or local air pollution control agency. Some generators, particularly smaller ones, are not required by all state or local authorities to be permitted and thus would be subject to reporting under the proposed rule as written.

Response: EPA has maintained the exclusion of emergency generators, and has excluded other emergency equipment from reporting. EPA has also revised the rule language to remove the prerequisite for a state or local permit. Please refer to the full definitions of emergency generator and emergency equipment in §98.6.

Commenter Name: Keith Overcash
Commenter Affiliation: North Carolina Division of Air Quality (NCDAQ)
Document Control Number: EPA-HQ-OAR-2008-0508-0588
Comment Excerpt Number: 24

Comment: If a permit for these sources is to be requested then the definitions should be aligned with other regulations. For example; definition of emergency generator should be aligned with NSPS subparts IIII and JJJJ depending on the fuel used. These rules also include the standard performance testing being limited to 100 hours or less but for a limited group of generators. Subpart IIII limits the generators affected to those units whose construction, modification or reconstruction began after July 11, 2005. Currently NC DAQ does not permit emergency generators if this is the only emission source at a facility. There is no definition in the proposed rule for peak-shaving generators. How does EPA propose to handle these emission sources? Does the facility report the emissions from these sources if the facility is over the reporting threshold or does the power company report their emissions? If a facility that exceeds the reporting threshold sells an emergency generator to a facility that is below the reporting threshold, does the new owner of the generator have to report the emissions? This provision in the rule will be a recordkeeping nightmare. How does EPA propose to track equipment sold by facilities that have exceeded the reporting threshold? The database for reporting the GHG emissions will have to be able to handle the facility-wide emissions from a facility that exceeds the threshold and emission source specific emissions from sources that changed ownership if the new owner's GHG emissions are below the reporting threshold.

Response: EPA believes that the applicability provisions and definitions of the rule should be appropriate in light of the purposes of the rule and so need not necessarily "align" with the applicability provisions and definitions in other rules. Because of the need for comprehensive, national greenhouse gas emissions data, the rule provides only limited exclusions from the reporting requirements. In the final rule, EPA has maintained the exclusion of emergency generators, has removed for such generators the 100-hour limitation and the requirement of designation in a state or local permit, and has excluded other emergency equipment from reporting.

However, emergency generators are limited to generators that "serve solely as a secondary source of mechanical or electrical power whenever the primary energy supply is disrupted or discontinued during power outages or natural disasters that are beyond the control of the owner or operator of a facility." Consequently, generators that serve "as a back-up power source under conditions of load shedding, peak shaving, power interruptions pursuant to an interruptible power service agreement, or scheduled facility maintenance" are not emergency generators. Generators that serve as back-up power sources under conditions of load shedding, peak shaving, power interruption pursuant to an interruptible power source agreement, or scheduled maintenance are not excluded because these operations are not necessarily infrequent, the equipment involved can be of widely varying sizes, and so the GHG emissions from these operations cannot be assumed to be, and treated as, insignificant. Because emissions are reported on a facility basis, peak-shaving generators' emissions will be reported by the facility where the generators are located. When generators are sold (and presumably moved) to a different facility, emissions will be reported consistent with that facility's reporting obligations under the rule in light of the sale. The owners and operators of the initial facility, and the owners and operators of the subsequent facility, where the generators are located will know when the sale took place and how the generators were operated when located at their respective facilities. EPA will rely on submissions by the facilities' designated representatives and, as appropriate, on audits to ensure that reporting obligations are met. While the commenter claims, without support or specific examples, that these circumstances would result in a "recordkeeping nightmare," EPA does not agree with the commenter's claim and believes that the reporting requirement is clear.

Commenter Name: Kimberly S. Lagomarsino
Commenter Affiliation: Mississippi Lime
Document Control Number: EPA-HQ-OAR-2008-0508-1568
Comment Excerpt Number: 3

Comment: Mississippi Lime Company agrees with EPA's proposal for facilities to NOT report emissions from portable equipment or generating units designated as emergency generators in a permit issued by a state or local air pollution control agency, as contained in Section V.C.1 of the Preamble. Such emissions compose a tiny fraction of overall facility GHG emissions.

Response: EPA appreciates the comment, and has maintained the exclusion of emergency generators and portable equipment, and has excluded other emergency equipment from reporting. EPA has also revised the rule language to remove the prerequisite for a state or local permit. Please refer to the full definitions of portable equipment, emergency generators, and emergency equipment in §98.6.

Commenter Name: Sarah B. King
Commenter Affiliation: DuPont Company
Document Control Number: EPA-HQ-OAR-2008-0508-0604.1
Comment Excerpt Number: 24

Comment: DuPont agrees with EPA that the reporting of GHG emissions from portable equipment and emergency generators is not necessary. This is supported by their infrequent use and resulting relatively small contribution to the total greenhouse gas inventory. Further, DuPont believes that coverage by a permit should not be a requirement for exclusion, but that the definitions of "Emergency generator" and "Portable equipment" in §98.6 are sufficient to delineate the excluded units

Response: EPA has maintained the exclusion of emergency generators, and has excluded other emergency equipment from reporting. EPA has also revised the rule language to remove the prerequisite for a state or local permit. Please refer to the full definitions of emergency generator and emergency equipment in §98.6. Portable equipment, as defined in §98.6, is also exempt from reporting.

Commenter Name: Lauren E. Freeman
Commenter Affiliation: Hunton & Williams LLP
Document Control Number: EPA-HQ-OAR-2008-0508-0493.1
Comment Excerpt Number: 22

Comment: EPA solicits comment on whether an emergency generator should be exempt only if it is designated as such in a permit. 74 Fed. Reg. at 16,480. Because some of these generators are too small to require a permit, or to be covered in existing permits, a permit should not be required for the exemption under this rule. UARG suggests that EPA exempt a generator under this rule if (1) it meets the definition of "emergency generator" in Subpart A of the rule, or (2) the generator is otherwise identified as an emergency generator in a permit.

Response: EPA has maintained the exclusion of emergency generators, and has excluded other emergency equipment from reporting. EPA has also revised the rule language to remove the prerequisite for a state or local permit. Please refer to the full definitions of emergency generator and emergency equipment in §98.6.

Commenter Name: Patrick J. Nugent
Commenter Affiliation: Texas Pipeline Association (TPA)
Document Control Number: EPA-HQ-OAR-2008-0508-0460.1
Comment Excerpt Number: 21

Comment: TPA supports proposed §98.30(b), which would exclude portable equipment and generating units designated as emergency generators in state or local permits from the rule's coverage.

Response: EPA appreciates the commenter's support. EPA has maintained the exclusion of emergency generators, and has excluded other emergency equipment from reporting. EPA has also revised the rule language to remove the prerequisite for a state or local permit. Please refer to the full definitions of emergency generator and emergency equipment in §98.6.

Commenter Name: J. P. Blackford
Commenter Affiliation: American Public Power Association (APPA)
Document Control Number: EPA-HQ-OAR-2008-0508-0661.1
Comment Excerpt Number: 21

Comment: EPA requested comments on its proposal "to not require reporting of emissions from portable equipment or generating units designated as emergency generators in a permit issued by a state or local air pollution control agency. [The EPA] request[s] comment on whether or not a permit should be required for these emergency generators." APPA believes that such a permit should not be required to exempt these emergency generators from reporting. Many emergency generators are too small to require a state permit. This would be overly burdensome to affected facilities and the permitting authority. In addition, by the very nature of the generator being used solely for "emergencies," the emissions from those generators are minimal compared to the rest of the electric utility sector. In the event of an emergency, the most important consideration for the electric utility is providing power for our customers; asking the utility to maintain records to allow the calculation of GHG emissions from those emergency generators may impede the main goal of restoring power as quickly as possible to our customers.

Response: EPA has maintained the exclusion of emergency generators, and has excluded other emergency equipment from reporting. EPA has also revised the rule language to remove the prerequisite for a state or local permit. Please refer to the full definitions of emergency generator and emergency equipment in §98.6.

Commenter Name: Lauren E. Freeman
Commenter Affiliation: Hunton & Williams LLP
Document Control Number: EPA-HQ-OAR-2008-0508-0493.1
Comment Excerpt Number: 21

Comment: Although EGU is defined in proposed §98.6 as "any unit that combusts solid, liquid, or gaseous fuel and is physically connected to a generator to produce electricity," Subpart D explicitly excludes "portable equipment" or generating units designated as "emergency generators" in a state or local permit. Proposed §98.40(b). As a result, the existence of an emergency generator would not itself be enough to subject a unit to Subpart D. EPA should make clear in the final rule that this exemption for emergency generators also means that Subpart D does not include a "methodology" that would otherwise subject such units to reporting.

Response: The direction of the comment is unclear, but EPA has clarified the applicability under Subpart D to apply only to Acid Rain Program units and other units already reporting CO_2 emissions to EPA under 40 CFR Part 75.

Commenter Name: Michael Carlson
Commenter Affiliation: MEC Environmental Consulting
Document Control Number: EPA-HQ-OAR-2008-0508-0615
Comment Excerpt Number: 21

Comment: We urge the agency to include an exemption under proposed Subpart C for units used solely for comfort heating. Such an exemption would be consistent with other reporting requirements under the agency's air programs.

Response: See the Preamble and separate comment response document volume for the response on de minimis reporting for small emission points.

Because of the need for comprehensive, national greenhouse gas emissions data, the final rule provides only limited exclusions from the reporting requirements. In light of this need for comprehensive data, EPA has instead taken the approach of limiting the exclusions but allowing reporting methods that provide data of a sufficient level of quality and consistency for the purposes of this rule but that reduce the reporting burden on reporters. In §98.30, EPA has excluded from reporting, for example, emergency generators and other emergency equipment, but has not adopted an exclusion for "comfort heating." The commenter fails to define what is meant by "comfort heating," much less explained how the suggested exclusion would be consistent with reporting requirements in other programs. In any event, the commenter's category of units used solely for comfort heating presumably would include sources providing only heating for individuals, whether in an industrial, commercial, institutional, or residential setting. EPA notes that the category of stationary fuel combustion sources already excludes residential sources. With regard to "comfort heating" in industrial, commercial, and institutional facilities, sources providing such heating will likely be routinely used and will be of widely varying sizes depending on the size of the facility involved, and so the GHG emissions from these units cannot be assumed to be, and treated as, insignificant. For the reasons discussed above, this category of sources is not excluded from reporting.

Commenter Name: Marcelle Shoop
Commenter Affiliation: Rio Tinto Services, Inc.
Document Control Number: EPA-HQ-OAR-2008-0508-0636.1
Comment Excerpt Number: 43

Comment: EPA requests comment on whether or not a permit should be required for emergency generators as a condition for them to be excluded from emission reporting requirements. (74 Fed. Reg. at 16480) If emergency generators are truly used for emergency purposes, their emissions should in most cases be insignificant and should not be subject to the GHG emissions reporting requirements.

Response: EPA has maintained the exclusion of emergency generators, and has excluded other emergency equipment from reporting. EPA has also revised the rule language to remove the prerequisite for a state or local permit. Please refer to the full definitions of emergency generator and emergency equipment in §98.6.

Commenter Name: Benjamin Brandes
Commenter Affiliation: National Mining Association (NMA)
Document Control Number: EPA-HQ-OAR-2008-0508-0466.1
Comment Excerpt Number: 21

Comment: EPA does not provided definitions in the proposed reporting rule for "combustion source" or "combustion unit." NMA requests that EPA provide definitions for these terms, or alternatively revise the regulation to clarify that GHG emissions from a combustion source or a combustion unit are those that are emitted from a stack serving the unit. NMA believes that EPA's intent is to require emissions reporting from non-fugitive stationary combustion sources, and therefore requests that EPA make its intentions clear in a final rule.

Response: In response to the comments, EPA does not believe that any additional language is needed to address the differences between the terms "combustion source," "combustion unit," and "device," as they are used in Subpart C. As stated in §98.30 of the final rule, "Stationary fuel combustion sources are devices that combust solid, liquid, or gaseous fuel, generally for the purposes of producing electricity, generating steam, or providing useful heat or energy for industrial, commercial, or institutional use, or reducing the volume of waste by removing combustible matter." The use of the word "device" is not limited in any way by the definition of the source category, general stationary fuel combustion. "Source" refers to those devices that do meet the provisions of the definition of the source category, as presented in §98.30. "Unit" generally describes a device that could be subject to the reporting requirements (were it to meet the specifications listed in §98.30). EPA believes that as clarified by these explanations, revisions to the rule are unnecessary.

Commenter Name: Lorraine Krupa Gershman
Commenter Affiliation: American Chemistry Council (ACC)
Document Control Number: EPA-HQ-OAR-2008-0508-0423.2
Comment Excerpt Number: 41

Comment: In §98.30, EPA should also exclude flares, thermal oxidizers, and other air pollution control devices from the definition of stationary combustion sources requiring calculation and reporting of greenhouse gas emissions. These units typically have low emissions, would not have measured flow rates, and do not make a substantial impact on the total greenhouse gas inventory. Any requirement to include these sources would put an unnecessary costly burden on facilities to add flow measurement devices to the feed. For devices such as flares, which may have a widely variable flow rate, there are additional challenges to finding an appropriate flow measurement device capable of covering the range of flows encountered. EPA should clarify that flare emissions should only be included in the calculations of Subpart C of the rule if another subpart of the rule references ³flares´ or ³emission control´ equipment as a greenhouse gas emission source requiring calculation and reporting of emissions.

Response: EPA has expanded the list of exempted source categories in §98.30(b) to include portable equipment, emergency generators, other emergency equipment, irrigation well devices, and flares (unless another subpart requires flare emissions to be reported). EPA has also revised the Preamble and §98.33 to deal with certain unconventional combustion processes and types of fuel. It is EPA's intent that sources allowed to use the Tier 1 and 2 methods, which include smaller combustion devices and should be inclusive of control devices such as thermal oxidizers, will only be required to report emissions from the combustion of fuels for which emission factors are provided. In the Preamble, EPA has explained that "EPA believes that the reporting requirements for Tier 1 and Tier 2 would only require the reporting of GHG emissions from supplementary traditional fossil fuels from devices such as thermal oxidizers, pollution control devices, fume incinerators, burnout furnaces, and other such equipment." EPA believes that these provisions satisfy the intent of Part 98, to collect accurate and consistent GHG emissions data that can be used to inform future decisions.

Commenter Name: Keith A. Nagel
Commenter Affiliation: ArcelorMittal USA and Severstal North America
Document Control Number: EPA-HQ-OAR-2008-0508-0496.1
Comment Excerpt Number: 31

Comment: EPA has requested comment on §98.30(b)'s proposed exclusion of "emergency generators in a permit issued by a state or local air pollution control agency" from regulation under Subpart C. While we agree with the exemption of emergency generators, we see no reason why permitting of these small, rarely used sources is necessary. Requiring permitting would only increase the permitting burden on states and facilities with no corresponding benefit. Instead, EPA can rely on the Proposed Rule's definition of "emergency generator" as an appropriate way to limit operation and testing of (and thus emissions from) these emergency generation units.

Response: EPA has maintained the exclusion of emergency generators, and has excluded other emergency equipment from reporting. EPA has also revised the rule language to remove the prerequisite for a state or local permit. Please refer to the full definitions of emergency generator and emergency equipment in §98.6.

Commenter Name: Jeff A. Myrom
Commenter Affiliation: MidAmerican Energy Holdings Company
Document Control Number: EPA-HQ-OAR-2008-0508-0581.1
Comment Excerpt Number: 28

Comment: MidAmerican agrees that portable and emergency generating equipment is not a significant source of emissions and emissions from portable and emergency generators should not be included in the reporting requirements, nor should a permit for greenhouse gas emissions be required for emergency generators.

Response: EPA has maintained the exclusion of emergency generators, and has excluded other emergency equipment from reporting. EPA has also revised the rule language to remove the prerequisite for a state or local permit. Please refer to the full definitions of emergency generator and emergency equipment in §98.6.

Commenter Name: Leslie Bellas
Commenter Affiliation: National Lime Association (NLA)
Document Control Number: EPA-HQ-OAR-2008-0508-0520.1
Comment Excerpt Number: 26

Comment: 40 C.F.R. §98.33 and Table C-1 require sources to include biomass fuel emissions in the emissions calculation for stationary fuel combustion sources. NLA believes that biomass should be excluded from the emissions calculation because biomass offsets carbon emissions from fossil fuel combustion, biomass is considered carbon neutral, see http://www.eia.doe.gov/oiaf/1605/coefficients.html, and biomass emissions are not included in determining whether a source meets the emissions threshold. NLA proposes that 40 C.F.R §98.33 be revised to exclude biomass (which does not encompass municipal solid waste) emissions calculation for stationary fuel combustion sources.

Response: See the response to comment EPA-HQ-OAR-2008-0508-0690.1 excerpt 1 corresponding to Section II. of the Preamble, and the response to comment EPA-HQ-OAR-2008-0508-0631.1 excerpt 71 corresponding to Subpart C for additional explanation of the reporting of biogenic CO_2 emissions.

EPA intends that biogenic CO_2 emissions should be reported; although EPA has decided to track biogenic emissions separately, they still must be included in the total CO_2 emissions reported. However, EPA notes (and believes that it has made clear in §98.2) that CO_2 emissions from biogenic fuels do not count toward the 25,000 metric ton threshold for reporting for stationary combustion units, although CH_4 and N_2O emissions from biogenic fuels must be considered. Including reporting of biogenic CO_2 at facilities that are already reporting for stationary combustion provides EPA with information on the use of biofuels as they relate to reductions of fossil CO_2 emissions over time. This reporting requirement also provides additional data for verification. Reporters not using CEMS are required only to report on emissions of biomass fuels for which default emission factors are provided, greatly reducing the burden associated with this data element.

Commenter Name: Linda Farrington
Commenter Affiliation: Eli Lilly and Company (Lilly)
Document Control Number: EPA-HQ-OAR-2008-0508-0680.1
Comment Excerpt Number: 24

Comment: Lilly believes the applicability of Subpart C should not include hazardous waste incinerators or thermal oxidizers used as air pollution control devices. If the EPA receives comments to the contrary and insists on including these types of units, the rule should only require emission calculations for CO_2 and not for CH_4 and N_2O. EPA states that, "Typically, nearly 100 percent of the fuel carbon is oxidized to CO_2. The CH_4 and N_2O emissions from stationary combustion are much smaller and indirectly related to the carbon and nitrogen contents of the fuel. In the U.S., CO_2 emissions represent over 99 percent of the total CO_2-equivalent (CO_2e) GHG emissions from all commercial, industrial, and electricity generation stationary combustion sources. CH_4 and N_2O emissions together represent less than one percent of the total CO_2e emissions from the same sources (U.S. EPA, 2008 – Inventory of U.S. Greenhouse Gases and Sinks)."

Response: While the commenter has not provided a reason for an exclusion of hazardous waste incinerators, EPA has revised the Preamble and §98.33 to deal with certain unconventional combustion processes and types of fuel. It is EPA's intent that sources allowed to use the Tier 1 and 2 methods, which include smaller combustion devices and should be inclusive of control devices such as thermal oxidizers, will only be required to report emissions from the combustion of fuels for which emission factors are provided. In the Preamble, EPA has explained that "EPA believes that the reporting requirements for Tier 1 and Tier 2 would only require the reporting of GHG emissions from supplementary traditional fossil fuels from devices such as thermal oxidizers, pollution control devices, fume incinerators, burnout furnaces, and other such equipment."

EPA notes that stationary combustion units that combust hazardous waste would report only the emissions from combustion of any fuels covered by Subpart C that are co-fired with hazardous wastes, not the hazardous wastes themselves.

See the response to comment EPA-HQ-OAR-2008-0508-0561.1 excerpt 2 for information on the reporting requirements for CH_4 and N_2O.

Commenter Name: Reed B. Hitchcock
Commenter Affiliation: Asphalt Roofing Manufacturers Association (ARMA)
Document Control Number: EPA-HQ-OAR-2008-0508-0794.1
Comment Excerpt Number: 4

Comment: For most stationary fuel combustion sources, EPA's calculation methodologies for calculating carbon dioxide emissions wisely focus only on emissions related to the fuel combusted. Section 98.33of the GHG Reporting Proposal makes clear that the Tier 1 and Tier 2 calculation methodologies use fuel emission factors to estimate carbon dioxide emissions. Tier 3 uses a calculation based on annual fuel use and measured carbon content of that fuel. ARMA agrees with this common-sense position. Yet in the preamble, EPA at times refers to carbon dioxide emissions from stationary fuel combustion sources, without noting that the emissions that must be reported are confined to those related to combustion of the fuel. See, for example, p. 16480, col. 3. This failure in certain places to point out that the carbon dioxide emissions that must be reported are limited to those related to fuel use could cause confusion for the regulated community. For example, many facilities use thermal oxidizers as an air pollution control device. While it is relatively straightforward to calculate carbon dioxide emissions from the fuel combusted in these thermal oxidizers, it would be difficult to measure emissions from the oxidation of volatile organic compounds in the gas exhaust stream. Thus, EPA should clarify in the preamble to the final rule that for units such as thermal oxidizers the facility should calculate and report only carbon dioxide emissions that are fuel-related.

Response: See the General Stationary Combustion source category Preamble section, as well as the separate comment response document volume, for the response on the definition of the source category.

EPA acknowledges the concerns of the commenter and has revised the Preamble and §98.33 to deal with certain unconventional combustion processes and types of fuel. It is EPA's intent that sources allowed to use the Tier 1 and 2 methods, which include smaller combustion devices and should be inclusive of control devices such as thermal oxidizers, will only be required to report emissions from the combustion of fuels for which emission factors are provided. In the Preamble, EPA has explained that "EPA believes that the reporting requirements for Tier 1 and Tier 2 would only require the reporting of GHG emissions from supplementary traditional fossil fuels from devices such as thermal oxidizers, pollution control devices, fume incinerators, burnout furnaces, and other such equipment."

Commenter Name: Filipa Rio
Commenter Affiliation: Alliance of Automobile Manufacturers (Alliance)
Document Control Number: EPA-HQ-OAR-2008-0508-0630.1
Comment Excerpt Number: 21

Comment: EPA is proposing to exclude reporting of portable equipment and generating units designated as emergency generators in a permit issued by a state or local air pollution control agency. While the premise of excluding the particular emergency generator sources also is appropriate, we are concerned that many of these units would still need to be included because they are not always addressed by air permits. Many state and local agencies provide exemptions from the requirement to obtain a permit for these types of units. Consequently, the proposed reporting exclusion would not be available as the units may not be identified in a permit. The Alliance proposes the emergency generator units as well as other pieces of equipment such as emergency air compressors and fire pumps be excluded regardless of their permitted status.

Response: EPA has maintained the exclusion of emergency generators, and has excluded other emergency equipment from reporting. EPA has also revised the rule language to remove the prerequisite for a state or local permit. Please refer to the full definitions of emergency generator and emergency equipment in §98.6.

Commenter Name: Lorraine Krupa Gershman
Commenter Affiliation: American Chemistry Council (ACC)
Document Control Number: EPA-HQ-OAR-2008-0508-0423.2
Comment Excerpt Number: 44

Comment: EPA has requested comment on whether a permit should be required for emergency generators excluded from greenhouse gas reporting requirements in §98.3(b). ACC agrees with EPA that the reporting of GHG emissions from emergency generators is not necessary. This is supported by their infrequent use and small contribution to the total greenhouse gas inventory. However, in §98.30(b), ACC does not believe that designation as an emergency generator in a permit should be necessary to exclude them from reporting. Some emergency generators might not be designated as ³emergency´ in their air permit even though they are for emergency use. Further, some may not be permitted at all. How the emissions from these generators are authorized will vary from state to state, depending on the details of state programs. For example, Indiana does not permit emergency generators at all, but rather considers them to be de minimis. Texas might cover them under a PBR (Permit by Rule). EPA should allow additional alternatives for omitting reporting for an emergency generator other than description in an air permit, such as hours of use and type of use. The emissions from emergency generators are very small compared to other stationary fuel combustion sources, and are insignificant compared to the inventory of greenhouse gases; therefore, discounting these emissions will not have a significant impact on the usefulness of the greenhouse gas inventory.

Response: EPA has maintained the exclusion of emergency generators, and has excluded other emergency equipment from reporting. EPA has also revised the rule language to remove the prerequisite for a state or local permit. Please refer to the full definitions of emergency generator and emergency equipment in §98.6.

Commenter Name: Keith Adams
Commenter Affiliation: Air Products and Chemicals, Inc.
Document Control Number: EPA-HQ-OAR-2008-0508-1142.1
Comment Excerpt Number: 19

Comment: The proposed rule appropriately excludes minor combustion sources from the definition of the Stationary Fuel Combustion source category, in particular process safety flares. Air Products supports this effort to minimize the burden on regulated facilities, as these units typically have very low emissions, typically do not have measured flow rates, and do not make a substantial impact on the total greenhouse gas inventory. Flares typically must operate over a widely variable flow rate and it is often very challenging to finding an appropriate flow measurement device capable of covering the range of flows encountered. Any requirement to include these sources would put an unnecessary costly burden on facilities to add flow measurement devices to the feed. As further evidence that these devices should be excluded, thermal oxidizers and air pollution control devices are excluded from greenhouse gas reporting requirements in the European Union. Where flaring operations are a routine operating control of a facility, such as in refineries, EPA has explicitly included emission estimation and reporting requirements. Air Products Comment: Clarify that flare emissions should only be included in the calculations of Subpart C of the rule if another subpart of the rule explicitly requires such emission calculation and reporting. Flare emissions should be otherwise excluded categorically or as a de mini mis source.

Response: EPA has revised the language of the final rule to expand the list of exempted source categories to include flares as defined in §98.6, except where another subpart of the rule requires flare emissions to be reported (see §98.30(b)). It is EPA's intent that sources allowed to use the Tier 1 and 2 methods, which include smaller combustion devices and should be inclusive of control devices such as thermal oxidizers, will only be required to report emissions from the combustion of fuels for which emission factors are provided. In the Preamble, EPA has explained that "EPA believes that the reporting requirements for Tier 1 and Tier 2 would only require the reporting of GHG emissions from supplementary traditional fossil fuels from devices such as thermal oxidizers, pollution control devices, fume incinerators, burnout furnaces, and other such equipment."

Commenter Name: Linda Farrington
Commenter Affiliation: Eli Lilly and Company (Lilly)
Document Control Number: EPA-HQ-OAR-2008-0508-0680.1
Comment Excerpt Number: 19

Comment: The language in §98.30(a) clearly indicates that "incinerators" are to be included in the general stationary fuel combustion source category. However, the EPA does not provide a definition of "incinerators," nor does it discuss the various types of incineration processes and their relative contribution to the nation's GHG emissions. Lilly believes further consideration is warranted for two types of incinerators, thermal oxidizers used for emissions control and incinerators used to destroy hazardous solid and liquid waste. a. Thermal oxidizers and fume incinerators are acceptable control methods for reducing emissions of VOCs and hazardous air pollutants (HAPs) and are often required in order to meet Part 60, 61, or 63 emission standards. These units would typically have low GHG emissions that result from the combustion of process VOC/HAP emissions and the combustion of supplemental fossil fuels necessary to maintain temperature in the incinerator. For instance, the CO_2 emissions from process vapor destroyed in a Regenerative Thermal Oxidizer at one of our sites was estimated to be 1% of the CO_2 emissions from the fuel used to maintain the RTO's temperature. Additionally, these estimated CO_2 emissions are less than 0.05% of the estimated direct CO_2 emissions from the site. Estimating GHG emissions from the combustion of supplemental fossil fuels, such as natural gas, is very straightforward since emission factors are readily available and flow measurement devices are usually present. However, the estimation of GHG emissions from the combustion of process VOC/HAP emissions is more problematic. As proposed, the mandatory reporting rule would require facilities with thermal oxidizers or fume incinerators to perform daily sampling to determine the carbon content of the process gas (Tier 3) or install CO_2 CEMS (Tier 4). In addition, facilities would also have to conduct stack tests to determine source specific emission factors for CH_4 and N_2O. Lilly believes this to be overly burdensome, given the relatively low GHG emissions expected from these air pollution control devices. b. Hazardous waste incinerators are not included in the current European Union Emissions Trading Scheme and Lilly suggests that they should also be excluded from the proposed mandatory GHG emission reporting rule. [Footnote: EU Directive 2003-87, Annex 1] According to EPA's 2005 estimates, there are fewer than 100 hazardous waste on-site incinerators in the United States. [Footnote: 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; October 12, 2005 Federal Register, p. 59530 [70FR59530]] The proposed GHG emission reporting rule would essentially require each of these units to conduct monthly testing of carbon content (Tier 3) or install CO_2 CEMS (Tier 4). As with thermal oxidizers, stack testing would also be necessary for hazardous waste incinerators in order to develop source specific emission factors for CH_4 and N_2O. Lilly does not believe it is appropriate or cost effective to require this degree of monitoring for such as small group of sources and we recommend that the EPA maintain consistency with the European Union by excluding hazardous waste incinerators from the reporting requirements in Subpart C. For the reasons described above, Lilly recommends the following addition to the language included in §98.30: "§98.30(c) This source category does not include air pollution control devices (including thermal oxidizers and fume incinerators) or hazardous waste incinerators."

Response: EPA acknowledges the concerns of the commenter and has revised the Preamble and §98.33 to deal with certain unconventional combustion processes and types of fuel. It is EPA's intent that sources allowed to use the Tier 1 and 2 methods, which include smaller combustion devices and should be inclusive of control devices such as thermal oxidizers, will only be required to report emissions from the combustion of fuels for which emission factors are provided. In the Preamble, EPA has explained that "EPA believes that the reporting requirements for Tier 1 and Tier 2 would only require the reporting of GHG emissions from supplementary traditional fossil fuels from devices such as thermal oxidizers, pollution control devices, fume incinerators, burnout furnaces, and other such equipment." In addition, §98.30 has been revised to exempt units that combust hazardous waste from reporting GHG emissions given that CEMS are not used to quantify CO_2 mass emissions and that no fuel listed in Table C-1 is also combusted in the unit (in that case only emissions from the supplemental fuel must be reported).

Commenter Name: Dan F. Hunter
Commenter Affiliation: ConocoPhillips Company
Document Control Number: EPA-HQ-OAR-2008-0508-0515.1
Comment Excerpt Number: 18

Comment: Typically, non-permitted emergency generators emit fewer emissions than permitted generators. Therefore, the state may not require a permit for an emergency generator. All emergency generators should also be excluded from the requirements of Subpart C.

ConocoPhillips recommends non-permitted emergency generators also be excluded from requirements of Subpart C.

Response: EPA has maintained the exclusion of emergency generators, and has excluded other emergency equipment from reporting. EPA has also revised the rule language to remove the prerequisite for a state or local permit. Please refer to the full definitions of emergency generator and emergency equipment in §98.6.

Commenter Name: Linda Farrington
Commenter Affiliation: Eli Lilly and Company (Lilly)
Document Control Number: EPA-HQ-OAR-2008-0508-0680.1
Comment Excerpt Number: 18

Comment: The language in §98.30(b) states that the source category does not include portable equipment or generating units designated as emergency generators in a permit issued by a state or local air pollution control agency. The EPA should not base the applicability of Subpart C on how a specific piece of equipment is permitted because permitting requirements for these types of units vary significantly from state to state. Some states, including Indiana, provide permit exemptions for emergency generators and fire pumps. [Footnote: 326 IAC 2-1.1-3(e)(25)(B)and(C)] The GHG reporting exemption for these kinds of engines should not depend on how the unit is permitted. A small, infrequently used engine will emit low quantities of GHGs regardless of how the unit is permitted or described in a permit. Thus, Lilly proposes the following revision to the language in §98.30(b): "§98.30(b) This source category does not include portable equipment, emergency generators, or emergency pumps." If the agency believes it is necessary to establish some regulatory parameters around engines used for emergencies to prevent abuse of the exemption, the rules should define emergency generators or emergency pumps, similar to how it is addressed in MACT and NSPS rules.

Response: EPA has maintained the exclusion of emergency generators, and has excluded other emergency equipment from reporting. EPA has also revised the rule language to remove the prerequisite for a state or local permit. Please refer to the full definitions of emergency generator and emergency equipment in §98.6.

Commenter Name: Sarah E. Amick
Commenter Affiliation: The Rubber Manufacturers Association (RMA)
Document Control Number: EPA-HQ-OAR-2008-0508-0647.1
Comment Excerpt Number: 15

Comment: Table C-3 provides emission factors for "distillate." (74 Fed. Reg. at 16640). However, distillate is not a defined term in the rule. In order to avoid confusion, the fuel types listed in the emission factor tables should be consistent with the defined terms.

Response: EPA has revised the Tables in the final rule considerably, and believes that the commenter's concern is addressed by the revision. Also, please see §98.6 for definitions on different classes of distillates (e.g., No.1, No.2, etc.).

Commenter Name: Kelly R. Carmichael
Commenter Affiliation: NiSource
Document Control Number: EPA-HQ-OAR-2008-0508-1080.2
Comment Excerpt Number: 15

Comment: NiSource agrees with INGAA recommendation of a de minimis threshold of 10 MMBtu/hr: The Proposed Rule does not include de minimis emission levels or exemption for small combustion sources that are not required to have a permit issued by a state or local air pollution control agency, and the rule notes that the burden associated with reporting small sources is addressed. Despite this claim, we believe that an unwarranted burden will be imposed and recommend that a de minimis or size-based exemption threshold be identified for combustion sources. NiSource agrees with the INGAA recommendation of a 10 MMBtu/hr exemption threshold. Many subject facilities include small combustors with minimal emissions. For example, water heaters at a small co-located office building and other small heaters will typically be present at subject facilities with much larger combustion sources. Typically, emissions will be inconsequential but activity data associated with these source types will not be readily available. Thus, an unnecessary amount of time will be spent devising fuel use or operating time estimates that will be highly uncertain and have an insignificant affect on facility emissions. Affected sources are faced with significant implementation challenges due to the breadth and timing of the Proposed Rule, and the additional burden associated with reporting trivial emissions is not warranted.

Response: See the Preamble, Section II. K., and the response to comment EPA-HQ-OAR-2008-0508-0423.2 excerpt 40 for the response on de minimis reporting for small emission points.

See the Preamble, Section II. E., and the response to comment EPA-HQ-OAR-2008-0508-0350.1 excerpt 3 for additional explanation of the selection and form of thresholds.

EPA appreciates the commenter's concern. The final rule includes further clarification and flexibility regarding aggregation and common pipe provisions that will reduce the burden on sources. First, in order to reduce the burden of compliance, EPA has explicitly allowed for the use of company records to determine fuel consumption. EPA has also removed the cumulative 250 mmBtu/hr restriction on unit aggregation, and has clarified the common pipe reporting option. In §98.30, EPA has expanded the list of sources excluded from coverage; however, this expansion does not include a 10 mmBtu/hr exemption threshold. These sources would be included under Subpart C for facilities that are required to comply with Part 98. In addition, EPA has maintained the exclusion of emergency generators, and has excluded other emergency equipment from reporting. EPA has also revised the rule language to remove the prerequisite for a state or local permit.

Commenter Name: Benjamin Brandes
Commenter Affiliation: National Mining Association (NMA)
Document Control Number: EPA-HQ-OAR-2008-0508-0466.1
Comment Excerpt Number: 23

Comment: NMA agrees that portable equipment and emergency generators are properly excluded from this rule and should not be required to be reported upon. Backup generators and portable equipment may vary tremendously in size and are typically seldom used. Requiring reporting on these sources would be unduly burdensome, especially on small businesses. Furthermore, collecting data on these sources would not add significantly to EPA's understanding of the CO_2e emissions produced in the United States.

Response: EPA has maintained the exclusion of emergency generators, and has excluded other emergency equipment from reporting. EPA has also revised the rule language to remove the prerequisite for a state or local permit. Please refer to the full definitions of emergency generator and emergency equipment in §98.6. Portable equipment, as defined in §98.6, is also exempt from reporting.

Commenter Name: Sean M, O'Keefe
Commenter Affiliation: Hawaiian Commercial and Sugar Company (HC&S)
Document Control Number: EPA-HQ-OAR-2008-0508-1138.1
Comment Excerpt Number: 2

Comment: EPA proposes that emissions from portable equipment or from generating units designated as emergency generators in a permit issued by a state or local air pollution control agency should not be included in the general stationary fuel combustion source category or in the electricity generation source category. Emissions from these units would therefore not be counted when determining whether a facility emits 25,000 metric tons of CO_2 equivalents (CO_2eq) per year, nor would they be included in the annual emissions to be reported to EPA. EPA requests comment regarding whether or not a permit should be required for such emergency generators. A&B supports EPA's proposal to exclude from reporting requirements emissions from portable equipment and emergency generating units. Annual emissions from these units are typically very low, due to their small size and/or very low operating hours, and tracking and reporting these emissions would impose an unreasonable burden on reporting facilities without significant benefit. A&B does not feel that generating units should have to be designated as emergency generators in a permit issued by a state or local air pollution control agency in order to be excluded from reporting. Some facilities with emergency generators may not be subject to state or local air permitting requirements; emissions from such unpermitted generators would be no higher than those from permitted generators and therefore should be covered by the same reporting exclusion. A&B believes that other emergency equipment with similarly low operating hours and correspondingly low emissions, such as backup fire pumps, should also be excluded from reporting requirements for the same reason that emergency generators should be excluded.

Response: EPA has maintained the exclusion of emergency generators, and has excluded other emergency equipment from reporting. EPA has also revised the rule language to remove the

prerequisite for a state or local permit. Please refer to the full definitions of emergency generator and emergency equipment in §98.6.

Commenter Name: See Table 10
Commenter Affiliation:
Document Control Number: EPA-HQ-OAR-2008-0508-0635
Comment Excerpt Number: 75

Comment: EPA requested comment on whether portable combustion equipment should be exempt. The oil and gas sector includes a number of large portable combustion units (e.g. drilling rigs, work over rigs, construction equipment, portable flares, portable generators, etc.). We recommend including these sources in the mandatory reporting rule.

Response: EPA refers the commenter to the definition of "portable" in §98.6, which the effect of which is to cause only some portable equipment to be exempt. The commenter should also note that EPA is not preparing a final version of the Oil and Natural Gas Systems (Subpart W) at this time.

Commenter Name: Joel R. Hall
Commenter Affiliation: INEOS Fluor Americas LLC
Document Control Number: EPA-HQ-OAR-2008-0508-1525
Comment Excerpt Number: 3

Comment: Exempt other emergency units in a permit issued by a state or local air pollution control agency. Paragraph 98.30(b) exempts "generating units designated as emergency generators in a permit issued by a state or local air pollution control agency" from the reporting requirements of Subpart C - General Stationary Fuel Combustion Sources. INEOS Fluor is unable to find any substantiation for this exemption in the preamble or the Technical Support Document. However, INEOS Fluor offers that other types of emergency units (firewater, cooling water, etc.) exist that are designated as emergency units in a permit issued by a state or local air pollution control agency. These units (typically a diesel driver) are likely to be of the same general type and size as emergency generators. INEOS Fluor's experience is that these units are generally operated for routine maintenance and during periodic performance checks. They are rarely operated for their intended used (i.e., extended periods of time). As such, INEOS Fluor requests that all emergency units (generators, firewater pumps, cooling water pumps, etc.) designated as emergency units in a permit issued by a state or local air pollution control agency be exempted from Subpart C in the final rule.

Response: EPA has maintained the exclusion of emergency generators, and has excluded other emergency equipment from reporting. EPA has also revised the rule language to remove the prerequisite for a state or local permit. Please refer to the full definitions of emergency generator and emergency equipment in §98.6.

Commenter Name: Bruce R. Byrd
Commenter Affiliation: AT & T Services, Inc.
Document Control Number: EPA-HQ-OAR-2008-0508-0426.1
Comment Excerpt Number: 2

Comment: The emergency generator exemption should not be limited to state permits. In exempting emergency generators from the proposed Reporting Rule's requirements, the proposed regulations limit the exemption to engines "designated as emergency generators in a permit issued by a state or local air pollution control agency." See Proposed 40 C.F.R. §98.30(b) and §98.40(b), 74 Fed. Reg. at 16631, 16641. This definition of "emergency generator" is unnecessarily limited. Many states do not have a permitting program that identifies "emergency generators" as such. States treat emergency generators in widely disparate manners, identifying them using permits, permits by rule, and exemptions. Many states do not have any separate program for emergency generators at all. Thus, under EPA's proposed rule, there will be many instances where emergency generators exist but are not explicitly identified by the permit issued by a state. Including such generators in the reporting process simply due to administrative differences in state licensing practices renders moot an otherwise important exemption. Consequently, EPA should supplement this definition with an exemption that applies consistently across the United States in order to avoid irrationally excluding emergency generators beyond those permitted by some states as emergency generators. EPA can achieve this result by hinging the exemption on the rule's definition of "emergency generator," and not necessarily on state and local permits. Specifically, we propose that 40 C.F.R. §98.30(b) and §98.40(b) should read: "This source category does not include portable equipment or emergency generators, as defined in this rule or designated in a permit, permit by rule, or exemption issued or otherwise authorized by a state or local air pollution control agency." This proposed change would not hinge the applicability of the rule solely on state law approaches, while at the same time providing EPA the flexibility to define the scope of the emergency generator exemption through the definition of "emergency generators" as described above.
Response: EPA has maintained the exclusion of emergency generators, and has excluded other emergency equipment from reporting. EPA has also revised the rule language to remove the prerequisite for a state or local permit. Please refer to the full definitions of emergency generator and emergency equipment in §98.6.

Commenter Name: Delaine W. Shane
Commenter Affiliation: Metropolitan Water District of Southern California (MWD)
Document Control Number: EPA-HQ-OAR-2008-0508-0551.1
Comment Excerpt Number: 2

Comment: We support the exclusion/exemption of emergency generators and engines from the Rule, which is consistent with CARB's reporting rule. The definition of emergency generator in the proposed rule needs to be comprehensive in order to exclude all such portable and stationary equipment and incorporate related exemption language as contained in other existing reporting rules, such as CARB's reporting rule and other CARB and SCAQMD rules for portable and stationary emergency engines. EPA's definition needs to be broad enough to include items such as maintenance and testing, demand response programs, and failure of a facility's internal power distribution system.

Response: EPA has maintained the exclusion of emergency generators, and has excluded other emergency equipment from reporting. EPA has also revised the rule language to remove the prerequisite for a state or local permit. Please refer to the full definitions of emergency generator and emergency equipment in §98.6, which address demand response procedures and other testing procedures.

Commenter Name: H. Allen Faulkner
Commenter Affiliation: Ascend Performance Materials, LLC, Decatur Plant
Document Control Number: EPA-HQ-OAR-2008-0508-1578
Comment Excerpt Number: 2

Comment: Currently, the stationary fuel combustion source category is defined as "devices that combust solid, liquid, or gaseous fuel, generally for the purposes of producing electricity, generating steam, or providing useful heat or energy for industrial, commercial, or institutional use, or reducing the volume of waste by removing combustible matter. Stationary fuel combustion sources include, but are not limited to, boiler, combustion turbines, engines, incinerators, and process heaters." Ascend operates two unique devices for the production of coke from coal at its Decatur Alabama Plant. To our knowledge these are the only two units like this in the United States. The coking units burn the volatiles out of the coal and produce a high grade "buckwheat" coke used primarily in the steel industry. Generally, half the coal input to Image is discharged as coke and the other half is the volatiles combusted. The units do have tube sections to recover the heat from the volatiles that are burned and generate steam as a byproduct that is used to heat our chemical processes. We sell the coke into the spot market, and only run the units to meet customer orders and demand. It is not practical to run the coking units solely for steam generation. The current definition of the stationary fuel combustion source category states that if a device is operated "... generally for the purposes of producing ..... steam .... or...useful heat...." it would be considered a stationary fuel combustion source. The coking units primary purpose is to produce coke product, even though some byproduct steam is generated and recovered. Therefore, we suggest that the word "generally" be replaced with the word "primary."

Response: See the individual source category section(s) of the Preamble and the source category comment response document(s) for the response on the definition of the source category.

Because of the need for comprehensive, national greenhouse gas emissions data, the final rule provides only limited exclusions from the reporting requirements. In light of this need for comprehensive data, EPA has instead taken the approach of limiting the exclusions but allowing reporting methods that provide data of a sufficient level of quality and consistency for the purposes of this rule but that reduce the reporting burden on reporters. The commenter's suggested revision would reduce, potentially significantly, the scope of the category of "stationary fuel combustion sources" to cover only sources whose "primary" purpose is "producing electricity, generating steam, or providing useful heat or energy for industrial, commercial, or institutional use, or reducing the volume of waste by removing combustible matter", rather than sources that "generally" combust fuel (i.e., combust fuel during normal operation) for such purposes. The commenter provides no information about what facilities, other than its two facilities, might potentially be excluded from reporting as a result of the suggested change. However, it seems that the suggested change could arguably exclude facilities that produce electricity, steam, or useful heat or energy for another purpose (e.g., to manufacture a product) and thus could claim that latter purpose is their "primary" purpose. Not only would the excluded group of sources potentially be extensive, but also such sources would likely operate frequently and be of widely varying sizes. For all these reasons, the GHG emissions from these sources cannot be assumed to be, and treated as, insignificant. For the reasons discussed above, EPA rejects the commenter's suggested revision.

Commenter Name: Jeffrey A. Sitler
Commenter Affiliation: University of Virginia (UVA)
Document Control Number: EPA-HQ-OAR-2008-0508-0675.1
Comment Excerpt Number: 2

Comment: The University of Virginia (UVA) owns a variety of stationary combustion sources from large steam generating boilers at our Main Heat Plant to small residential furnaces and water heaters. Does the stationary source definition (§98.30) include small units such as residential type water heaters, furnaces, etc? These units are not included in our Title V emissions reporting. §98.30(a) states "stationary fuel combustion sources are devices that combust fuel, generally for the purposes of... providing useful heat or energy..." In the request for comments on de minimis exclusions G.2., a statement for the justification of the lack of de minimis exclusions states that the "proposed rule would affect only larger facilities, would only require reporting of significant emission points only..." In light of this statement, it would seem that small residential units would not be considered since individually they are not significant emission sources. We suggest modifying the text of §98.30(b) to include an exemption for small residential type units. If the smaller units are not included, we would suggest that a threshold Btu/hr limit be used, such as 200,000 Btu/hr, which would eliminate most home sized hot water units and smaller furnaces. Virginia air regulation, 9 VAC 5-80-720 C2, considers the following fuel combustion units as insignificant sources: 1. Those with heat input levels less than 10 MMBtu/hr rated input, using natural gas. 2. Those with heat input levels less than 1 MMBtu/hr rated input, using distillate oil (maximum 0.5% sulfur). Alternatively, potential language for exempting small combustion sources can be taken from an EPA survey we completed last year. The survey was gathering information to support a revised NESHAP for boilers and process heaters. The following text is the response to a question on whether space heaters or water heaters were in the scope of the survey: "If a boiler serves as a space heater it is included in the survey. If a boiler serves as a hot water heater (as defined below) it is not included. Any unit that is not a boiler, but provides comfort heat is not included in the scope of the survey. A hot water heater means a closed vessel with a capacity of no more than 120 U.S. gallons in which water is heated by combustion of gaseous or liquid fuel and is withdrawn for use external to the vessel at pressures not exceeding 160 psig, including the apparatus by which the heat is generated and all controls and devices necessary to prevent water temperatures from exceeding 210 °F (99 °C)."

Response: See the Preamble, Section II. K., and the response to comment EPA-HQ-OAR-2008-0508-0423.2 excerpt 40 for the response on de minimis reporting for small emission points.

See the Preamble, Section II. E., and the response to comment EPA-HQ-OAR-2008-0508-0350.1 excerpt 3 for additional explanation of the selection and form of thresholds.

In the final rule the definition of "stationary fuel combustion source" already excludes residential sources because it covers devices combusting fuel "generally for the purposes of producing electricity, generating steam, or providing useful heat or energy <u>for industrial, commercial, or institutional use</u>, or reducing the volume of waste by removing combustible matter" (§98.30(a) (emphasis added)). Consequently, EPA believes that it is unnecessary to add a specific exemption for "small residential type units" as suggested by the commenter. Whether the commenters' facilities that are referred to in the comment are covered by the stationary fuel combustion source definition depends on the specific circumstances of those facilities. Currently lacking such information about these facilities, EPA cannot make a determination at this time with regard to the commenter's equipment, but intends to do so in the future, upon request, when such information is provided.

Commenter Name: Lorraine Krupa Gershman
Commenter Affiliation: American Chemistry Council (ACC)
Document Control Number: EPA-HQ-OAR-2008-0508-0423.2
Comment Excerpt Number: 42

Comment: In §98.30(a), EPA has not defined "incinerator." Without a definition, it could apply to a very broad range of things from large waste incinerators to small thermal control devices for vent gas streams. While it may be appropriate to include non-hazardous waste incinerators due to the potential significant contribution to a facility's total GHG emissions, small devices may not be flow monitored and do not add a significant contribution to the total greenhouse gas inventory. It would be overly burdensome and unnecessarily costly to add these flow measurement devices to these sources to facilitate emission calculations.

Response: See the General Stationary Combustion source category section of the Preamble and the source category separate comment response document volume for the response on the definition of the source category.

EPA acknowledges the concerns of the commenter, and has revised §98.30 of the final rule to clarify the definition of the general stationary fuel combustion source category and provide an expanded list of sources exempted from GHG emissions reporting under Subpart C. The commenter should consult the revised rule which includes devices that combust fuel for the purpose of "reducing the volume of waste by removing combustible manner" in the definition of the stationary combustion source category, and exempts flares (except where required to report by another subpart) and devices that incinerate hazardous waste (with certain conditions). EPA has revised the Preamble and §98.33 to deal with certain unconventional combustion processes and types of fuel. It is EPA's intent that sources allowed to use the Tier 1 and 2 methods, which include smaller combustion devices and should be inclusive of control devices such as thermal oxidizers, will only be required to report emissions from the combustion of fuels for which emission factors are provided. In the Preamble, EPA has explained that "EPA believes that the reporting requirements for Tier 1 and Tier 2 would only require the reporting of GHG emissions from supplementary traditional fossil fuels from devices such as thermal oxidizers, pollution control devices, fume incinerators, burnout furnaces, and other such equipment."

Commenter Name: George H. Berghorn
Commenter Affiliation: Michigan Forest Products Council (MFPC)
Document Control Number: EPA-HQ-OAR-2008-0508-0721.1
Comment Excerpt Number: 2

Comment: A restrictive definition limits the use of forest biomass to meet the RFS mandate of 36 billion gallons by 2022, thus jeopardizing our ability to meet the standard. A restrictive standard creates a market barrier for forest biomass and creates an uneven playing field relative to other feedstocks. A broad definition of wood is necessary. A broad definition of forest biomass that appropriately addresses sustainability is essential. Sustainability is best addressed at the local level using established and familiar tools and processes, like state water quality best management practices, that have proven effective over time.

Response: EPA has finalized the biomass definition in §98.6 largely as proposed, with some additional language addressing the biogenic fractions of industrial and municipal wastes. The EPA believes the definition of biomass is defined broadly enough to include the majority of wood and forest biomass. In addition, addressing sustainability and certifying renewable fuels is beyond the scope of this rule.

Commenter Name: Lorraine Krupa Gershman
Commenter Affiliation: American Chemistry Council (ACC)
Document Control Number: EPA-HQ-OAR-2008-0508-0423.2
Comment Excerpt Number: 43

Comment: It is not clear whether EPA intended for facilities to report greenhouse gas emissions of hazardous waste burned in hazardous waste incinerators or combustors. For example, Table C-1 (74 FR 16481) does not mention hazardous waste fuels. ACC recommends that EPA exempt hazardous waste combustion units from the rule. These hazardous waste units would be small contributions to the total inventory and may vary widely in flow rate and composition, thus making the calculations more difficult. Furthermore, EPA has recognized the small contribution by exempting hazardous waste from the calculations and reporting in the landfill subpart of this proposed rule.

Response: See the General Stationary Combustion source category section of the Preamble and the separate source category comment response document volume for the response on the definition of the source category.

EPA acknowledges the concerns of the commenter, and has revised §98.30 of the final rule to clarify the definition of the general stationary fuel combustion source category and provide an expanded list of sources exempted from GHG emissions reporting under Subpart C. The commenter should consult the revised rule which exempts combustion of hazardous waste, unless CEMS are used to quantify CO_2 mass emissions, or any fuel listed in Table C-1 is also combusted in the unit.

Commenter Name: Geoffrey Cullen
Commenter Affiliation: Can Manufacturers Institute (CMI)
Document Control Number: EPA-HQ-OAR-2008-0508-0703.1
Comment Excerpt Number: 2

Comment: EPA is using a very broad definition of "General Stationary Fuel Combustion Sources." The rule defines General Stationary Fuel Combustion Sources as: "devices that combust solid, liquid, or gaseous fuel, generally for the purposes of producing electricity, generating steam, or providing useful heat or energy for industrial, commercial, or institutional use, or reducing the volume of waste by removing combustible matter. Stationary fuel combustion sources include, but are not limited to, boilers, combustion turbines, engines, incinerators, and process heaters." CMI is concerned that the proposed definition is so broad that it might include pollution control devices such as thermal oxidizers that combust natural gas. CMI urges EPA to add an explicit exclusion from the definition of General Stationary Fuel Combustion Sources for "air pollution control devices." EPA does exclude "portable equipment or generating units designated as emergency generators in a permit issued by a state or local air pollution control agency" from the definition of Stationary Fuel Combustion Source. CMI supports this exclusion.

Response: EPA has revised the Preamble and §98.33 to deal with certain unconventional combustion processes and types of fuel. It is EPA's intent that sources allowed to use the Tier 1 and 2 methods, which include smaller combustion devices and should be inclusive of control devices such as thermal oxidizers, will only be required to report emissions from the combustion of fuels for which emission factors are provided. In the Preamble, EPA has explained that "EPA believes that the reporting requirements for Tier 1 and Tier 2 would only require the reporting of GHG emissions from supplementary traditional fossil fuels from devices such as thermal oxidizers, pollution control devices, fume incinerators, burnout furnaces, and other such equipment."

Commenter Name: Bruce R. Byrd
Commenter Affiliation: AT & T Services, Inc.
Document Control Number: EPA-HQ-OAR-2008-0508-0426.1
Comment Excerpt Number: 1

Comment: The definition of "emergency generator" must encompass emergency demand response. EPA proposes to explicitly exclude certain emergency generators from the General Stationary Fuel Combustion Source and Electricity Generation subparts. See Proposed 40 C.F.R. §98.30(b) and §98.40(b), 74 Fed. Reg. at 16631, 16641. The currently proposed definition, however, could be read to disqualify generators from the emergency classification if the generator is used or could be used for the critical function of providing emergency demand response. Importantly, while the definition initially makes it clear that emergency generators providing a "secondary source" of electrical power during "power outages" are within the definition, this last sentence creates ambiguity by removing from the definition generators that respond to "power interruptions pursuant to an interruptible power service agreement." Thus, as a result of this ambiguity, the definition arguably could be read to impose significant reporting obligations on generators that participate in emergency demand response programs despite the clear statement at the outset of the definition purporting to exempt secondary sources of electrical power in "emergency situations." In other words, it is possible that "power interruptions pursuant to an interruptible power service agreement" could be read to include the emergency generators that participate in emergency demand response programs that are often our nation's last line of defense against power outages. We believe EPA must clarify the final rule to provide that generators providing emergency power under emergency demand response programs are properly within the "emergency generator" definition. Emergency demand response programs are critical to our environment and the security of the nation's power grid. Developed by companies that manage the electric grid, these programs are only used in the most serious emergencies to prevent brownouts and blackouts due to insufficient supply of power to the grid. Participants in an emergency demand response program have no control over the timing of these events, they are identified by the grid managers, who direct participants to comply. Participants in such programs do not supply power to the grid; all power is used at the individual facility. The emergency demand response programs are only instituted in cases of true emergencies. Following are three examples of this type of emergency demand response program. 1. In New England, the demand response program is only implemented once ISO New England, the Regional Transmission Organization (RTO) serving Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont, declares Operating Procedure 4, Action 12. Since the demand response program was initiated in New England in 2002, there have been three days on which ISO New England requested action in Connecticut, and on only one of those days was action requested for all of New England. 2. The mid-Atlantic RTO, PJM, activates its Emergency Load Response Program (ELRP) according to the procedures in the PJM Manual 13 Emergency Operations for a PJM Declared Emergency. In the past five years, the ELRP has only been activated five times for a total of 20 hours. 4. The Electricity Reliability Council of Texas (ERCOT) activates its Emergency Interruptible Load Service (EILS) Program just before the electric grid is expected to fail. The EILS is integrated into ERCOT's Electrical Emergency Curtailment Plan and is activated during a Stage 3 emergency, where the alternative is blackouts. The EILS Program is designed for a maximum of six dispatches per year with a maximum of 24 hours. While participants in emergency demand response programs are compensated whether or not their engines are called, emergency demand response programs should not be confused with economic demand response programs or peak-shaving. Emergency demand response programs are initiated by the transmission system operators when the threat of power outages is likely and are critical to maintaining available power during periods of extreme load on the electric power infrastructure. These unplanned events are out of the control of emergency generator owners or operators. As the examples above demonstrate, emergency generators providing such critical power are not major contributors to GHG emissions. In fact, as part of an effective emergency demand response program, they lead to a significant decrease in emissions. They are only used to save the grid when it is about to fail. In their absence, the grid would fail, and the generators would have to run to provide back-up power, a clearly exempted emergency use. And all generators on the grid would have to run, even those not enrolled in emergency demand response programs, dramatically increasing GHG emissions. Thus, the objectives of this reporting program are benefited by clearly exempting this category of generators. Refusing to exempt these generators would create a strong incentive to remove them from emergency demand response programs for two reasons. First, companies would have to carefully monitor thousands of these units' GHG emissions to determine whether they reached the 25,000 ton reporting threshold, even though they are rarely, if ever, used for emergency demand response. And second, companies might have to report emissions for their entire facilities if the emergency generator pushed them over the threshold. This might seem very unlikely because emergency demand response events are so rare. But the rule as written does not exempt particular generation activities, it exempts particular generators. Thus, if a generator participates in an emergency demand response program, all of its emissions, including emissions generated during power outages, maintenance, or natural disasters — could count toward the 25,000 ton threshold. This is true even if a facility never actually runs its generator during an emergency demand event. Even worse, if a natural disaster or power outage ever required sufficient generator use to meet the threshold, the facility would have to report its emissions in perpetuity because of the proposed rule's oncein-always-in structure. Unless the rule is clarified, many companies will withdraw their generators from these crucial programs. To clearly achieve the goal of exempting these critical generators from the reporting rule, EPA should remove the current ambiguity by modifying the existing emergency generator definition as proposed in the following text: Emergency generator means a stationary internal combustion engine that serves solely as a secondary source of mechanical or electrical power whenever the primary energy supply is disrupted or discontinued during power outages or natural disasters that are beyond the control of the owner or operator of a facility. Emergency engines operate only during emergency situations or for standard performance testing procedures as required by law or by the engine manufacturer. The hours of operation per calendar year for such standard performance testing shall not exceed 100 hours. An engine that serves as a back-up power source under conditions of load shedding, peak shaving, or scheduled facility maintenance shall not be considered an emergency engine. An engine that provides energy to a facility during periods in which the Regional Transmission Organization or other local or regional entity responsible for maintaining reliability of electrical operations directs the implementation of emergency demand response procedures shall be considered an emergency generator, so long as it otherwise meets the requirements of this definition.

Response: In the final rule, EPA has maintained the exclusion of emergency generators, has removed for such generators the 100-hour limitation and the requirement of designation in a state or local permit, and has excluded other emergency equipment from reporting. However, under the rule, emergency generators are limited to generators that "serve solely as a secondary source of mechanical or electrical power whenever the primary energy supply is disrupted or discontinued during power outages or natural disasters that are beyond the control of the owner or operator of a facility" (emphasis added). Such generators operate "only during emergency situations, for training of personnel under simulated emergency conditions, as part of emergency demand response procedures, or for standard performance testing procedures as required by law or by the generator manufacturer" (emphasis added). Consequently, generators that serve "as a back-up power source under conditions of load shedding, peak shaving, power interruptions pursuant to an interruptible power service agreement, or scheduled facility maintenance" are not emergency generators.

The commenter states, with no support or specific examples, that the exclusion of generators used during "'power interruptions pursuant to an interruptible power service agreement' could be read to include the emergency generators that participate in emergency demand response programs." The commenter does not explain why this interpretation would be reasonable or why, for example, a transmission system operator initiating emergency demand response procedures would not expressly invoke such procedures and thereby distinguish the event from cases of power interruptions pursuant to an interruptible power service agreement. Moreover, the commenter does not claim that generators used for peak-shaving (e.g., power interruptions pursuant to an interruptible power service agreement) should be treated as emergency generators, and EPA continues to believe that they should not. Yet, the commenter's suggested language revisions would remove the provision that generators that serve "as a back-up power source under conditions of . . . power interruptions pursuant to an interruptible power service agreement" are not emergency generators. EPA rejects the commenter's suggested language as unnecessary and confusing.

Commenter Name: Mark A. Dupuis
Commenter Affiliation: International Paper Products Corporation (IPPC)
Document Control Number: EPA-HQ-OAR-2008-0508-0445.1
Comment Excerpt Number: 1

Comment: IPPC is pleased that the United States Environmental Protection Agency's Proposed Rule "Mandatory Reporting of Greenhouse Gases" allows for exclusion of carbon dioxide (CO_2) emissions from biogenic (biomass) fuels used in General Stationary Fuel Combustion. It is IPPC's position that the development of this rule and subsequent policies regarding its implementation should include Paper Derived Fuel (PDF). There is adequate and available analytical technology to ascertain the biogenic portion of PDF and it is well recognized that paper is derived from biomass (TSD for Stationary Fuel Combustion Emissions, Section 3.3.2; Intergovernmental Panel on Climate Change Guidelines). Manufacture of Enviro-Fuelcubes® is the result of a tightly controlled acquisition process. Therefore, the quality and positive combustion characteristics of Enviro-Fuelcubes® are high because PDF is manufactured from carefully specified and selected non-recyclable secondary raw materials. The result is a fuel having a nominal Higher Heat Value (HHV) of 10,000 BTU per pound on a consistent basis and over 75% of that energy is biogenic in origin. The remaining (fossil) energy content of Enviro-Fuelcubes® is due to inseparable coatings or mixtures of clean, non-recyclable, non-hazardous polymers whose origins are identified and verified.

Response: EPA appreciates the comment but notes that CO_2 emissions from biomass are excluded from the threshold determination for Subpart C, but facilities that report due to fossil CO_2 emissions must report CO_2 emissions from combustion of biomass. The rule provides for separate accounting of biomass and fossil CO_2 emissions from mixed fuels. In most cases, Tier 1 may be used to calculate biogenic emissions. When a premixed blend of biomass and fossil fuel is combusted, the facility may determine the quantity of biomass combusted using the best available information. Furthermore, EPA has allowed units that use CEMS to measure total CO_2 emissions to determine the biogenic portion of emissions for units that combust a combination of biomass- and fossil-derived fuels using ASTM Methods D7459-08 and D6866-06a.

Commenter Name: Gregory A. Wilkins
Commenter Affiliation: Marathon Oil Corporation
Document Control Number: EPA-HQ-OAR-2008-0508-0712.1
Comment Excerpt Number: 103

Comment: Marathon would like to receive further clarification on the issue of whether or not building heating would be applicable under this rule. Marathon interprets that building heating would be excluded from this rule or be allowed to be considered de minimis. The emissions from building heating would be far less than 1% of any refinery's total emissions.

Response: See the Preamble and separate comment response document volume for the response on de minimis reporting for small emission points. See response to comment EPA-HQ-OAR-2008-0508-0615 excerpt 21 and response to comment EPA-HQ-OAR-2008-0508-0675.1 excerpt 2 for an explanation of the treatment of residential facilities.

EPA has expanded the list of exempted source categories to include portable equipment, emergency generators, other emergency equipment, irrigation well devices, and flares, but has not excluded building heating from this rule. EPA has also removed the cumulative 250 mmBtu/hr restriction on unit aggregation and clarified common pipe metering, and believes that the expanded availability of these options will reduce the reporting burden on facilities.

Commenter Name: Lorraine Krupa Gershman
Commenter Affiliation: American Chemistry Council (ACC)
Document Control Number: EPA-HQ-OAR-2008-0508-0423.2
Comment Excerpt Number: 45

Comment: Also in §98.30(b), the term "emergency generators" should be changed to ³emergency stationary RICE.´ Many facilities use combustion units (e.g., diesel engines) as the motive force for pumps, to ensure fire water availability and process fluid movement during power outages. ACC recommends that EPA exclude all emergency stationary reciprocating internal combustion engines (RICE) as the term is defined in 40 CFR 63 Subpart ZZZZ (§63.6675). These are sources whose operation is limited to emergency situations and whose emissions are negligible when compared to other stationary combustion sources. Exclusion of these sources would exclude sources such as stationary RICE used to pump water in the case of fire or flood, for example. For the reasons above, ACC recommends that EPA revise §98.30(b) to read as follows: "(b) This source category does not include portable equipment or units that are emergency stationary reciprocating internal combustion engines." GHGs to report - §98.32 The text of §98.32 should be revised by adding text to the end of the sentence as follows (new language underlined): ". . . each stationary fuel combustion unit except as allowed by §98.36(c)."

Response: EPA asks the commenter to please refer to the full definitions of emergency generator and emergency equipment in §98.6, which include reciprocating internal combustion engines (RICE), and include ". . . secondary sources of *mechanical* and electrical power . . ."

Commenter Name: Sean M, O'Keefe
Commenter Affiliation: Hawaiian Commercial and Sugar Company (HC&S)
Document Control Number: EPA-HQ-OAR-2008-0508-1138.1
Comment Excerpt Number: 4

Comment: A&B also strongly supports a de minimis exemption for small stationary combustion sources at reporting facilities, similar to reduced requirements for "insignificant activities" allowed under state Title V permit programs. Typically, such activities may be exempted from emissions reporting and other Title V permit requirements based upon the size or type of equipment or based upon their emissions. For example, activities at the HC&S Puunene

Sugar Mill classified as "insignificant" under Hawaii's Title V permit program include an emergency diesel generator and a secondary fire pump (both classified as insignificant based upon the type of equipment) and various small diesel or propane-fired stationary equipment all with rated heat input capacities less than one million BTUs per hour (classified as insignificant based upon their size and corresponding emissions). Even assuming that all of this small equipment operated continuously at maximum capacity for 8,760 hours per year, combined theoretical maximum emissions of carbon dioxide would amount to less than five percent of the 25,000 tons per year reporting threshold in the proposed rule; since in reality such equipment will operate far less frequently, actual combined emissions would amount to less than one percent of the proposed facility reporting threshold, and to an even smaller percentage of the facility's total GHG emissions. A&B believes that the considerable effort and expense required to annually monitor, record, and report emissions from numerous de minimis sources at a reporting facility is unreasonable and unwarranted given the very minimal impact on the accuracy of reported GHG emissions that exclusion of these sources would have. While we appreciate EPA's efforts to minimize this burden through its proposal to allow emissions aggregation from a group (or groups) of small units at a facility, this measure only reduces (but does not eliminate) the reporting burden for these sources; it does not alleviate the need to monitor, record, and track fuel usage for the individual units within an aggregated group, nor to maintain associated records. A&B therefore recommends that EPA incorporate into the rule a reporting exclusion for de minimis sources, and that EPA define "de minimis sources" as all sources at a facility below a specified heat input capacity (e.g., one million BTU per hour) contributing, in the aggregate, less than one percent of total facility emissions of CO_2 equivalents. Facilities should not be required to monitor, record, or report GHG emissions from any units which meet the criteria for classification as de minimis sources.

Response: See the Preamble, Section II. K., and the response to comment EPA-HQ-OAR-2008-0508-0423.2 excerpt 40 for the response on de minimis reporting for small emission points.

EPA has expanded the list of exempted source categories to include portable equipment, emergency generators, other emergency equipment, irrigation well devices, and flares. EPA has also removed the cumulative 250 mmBtu/hr restriction on unit aggregation, and believes that the expanded availability of this option will reduce the reporting burden on facilities.

Commenter Name: Curtis J. Winner
Commenter Affiliation: New Mexico Gas Company (NMGC)
Document Control Number: EPA-HQ-OAR-2008-0508-0585
Comment Excerpt Number: 2

Comment: In the preamble, EPA requests comments as to whether a permit should be required for emergency generators. NMGC does not think a permit should be required for emergency generators.

Response: EPA has maintained the exclusion of emergency generators, and has excluded other emergency equipment from reporting. EPA has also revised the rule language to remove the prerequisite for a state or local permit. Please refer to the full definitions of emergency generator and emergency equipment in §98.6.

Commenter Name: Robert D. Bessette
Commenter Affiliation: The Council of Industrial Boiler Owners (CIBO).
Document Control Number: EPA-HQ-OAR-2008-0508-0513.1
Comment Excerpt Number: 18

Comment: In the proposed rule, EPA proposes to exclude the reporting of only such portable equipment and generating units designated as emergency generators that have been permitted under the New Source Review (NSR) program. As stated here, CIBO agrees with the exclusion of these sources from the reporting obligations, but such pieces are not always explicitly covered by an NSR permit based on state NSR programs, which might specifically exempt such units from the requirement to obtain a permit. Hence, based on the current language in the proposed rule, the proposed reporting exemption could not be utilized for those units not identified in a NSR permit. CIBO therefore recommends that EPA amend the proposed rule to exclude the reporting of these units regardless of their permitted status.

Response: EPA has maintained the exclusion of emergency generators, and has excluded other emergency equipment from reporting. EPA has also revised the rule language to remove the prerequisite for a state or local permit. Please refer to the full definitions of emergency generator and emergency equipment in §98.6.

Commenter Name: See Table 6
Commenter Affiliation:
Document Control Number: EPA-HQ-OAR-2008-0508-0679.1
Comment Excerpt Number: 70

Comment: Emergency generator §98.6 (p. 16620): The definition of 'Emergency generator' states "the hours of operation per calendar year for performance testing shall not exceed 100 hours." API requests that the specification of hours be removed from the definition of emergency generators. It is not reasonable to limit the number of hours. In addition, the definition in regards to the duration of operation for performance testing should be revised to be consistent with the existing Clear Air Act (CAA) regulations definition for emergency equipment that state testing of units should be minimized, but there is no time limit on the use of emergency equipment in emergency situations and for routine testing and maintenance. Refer to Stationary Combustion Turbines MACT (§63.6175) and Stationary Reciprocating Internal Combustion Engines MACT (§63.6675).

Response: EPA has eliminated the 100-hour limitation for emergency generators in the final rule. Please refer to the full definition of emergency generator in §98.6.

Commenter Name: Phillip McNeely
Commenter Affiliation: City of Phoenix, AZ
Document Control Number: EPA-HQ-OAR-2008-0508-0374.1
Comment Excerpt Number: 9

Comment: Recommend that the definition of emergency generators add "maintenance and repairs" to 100 hour operation limit. The edit indicated below would clarify the rule and make it consistent with the definition of emergency generators in the New Source Performance Standard Rule in 40 CFR 60 Subparts 1111 and JJJJ and in proposed 40 CFR 63 Subpart ZZZZ. Without this clarification, many affected facility owners would be required to either bring in portable generators for minor maintenance procedures or submit GHG records. Recommended edit to Subsection, 98.6 provided below. "Emergency generator means a stationary internal combustion engine that serves solely as a secondary source of mechanical or electrical power whenever the primary energy supply is disrupted or discontinued during power outages or natural disasters that are beyond the control of the owner or operator of a facility. Emergency engines operate only during emergency situations or for REPAIRS, MAINTENANCE, OR standard performance testing procedures as required by law or by the engine manufacturer. The hours of operation per calendar year for such REPAIRS, MAINTENANCE AND, standard performance testing shall not exceed 100 hours".

Response: In the final rule, EPA has addressed the concern raised by the commenter by eliminating the 100-hour limitation for emergency generators. Please refer to the full definition of emergency generator in §98.6.

Commenter Name: Lorraine Krupa Gershman
Commenter Affiliation: American Chemistry Council (ACC)
Document Control Number: EPA-HQ-OAR-2008-0508-0423.2
Comment Excerpt Number: 32

Comment: The definition of emergency generator states that the hours of operation per calendar year for performance testing shall not exceed 100 hours. The definition in regards to the duration of operation for performance testing should be revised to be consistent with existing Clear Air Act regulations definition for emergency equipment that state testing of units should be minimized, but there is no time limit on the use of emergency equipment in emergency situations and for routine testing and maintenance. See, for example, Stationary Combustion Turbines NESHAP (40 CFR §63.6 175) and Stationary Reciprocating Internal Combustion Engines NESHAP (40 CFR §63.6675). Furthermore, the definition of "emergency generator" should be changed to "emergency stationary RICE" to reflect the various types of equipment that can be used by facilities. ACC recommends that EPA utilize the definition in §63.6675: "Emergency stationary RICE means any stationary RICE that operates in an emergency situation. Examples include stationary RICE used to produce power for critical networks or equipment (including power supplied to portions of a facility) when electric power from the local utility is interrupted, or stationary RICE used to pump water in the case of fire or flood, etc. Emergency stationary RICE may be operated for the purpose of maintenance checks and readiness testing, provided that the tests are recommended by the manufacturer, the vendor, or the insurance company associated with the engine. Required testing of such units should be minimized, but there is no time limit on the use of emergency stationary RICE in emergency situations and for routine testing and maintenance. Emergency stationary RICE may also operate an additional 50 hours per year in non-emergency situations."

Response: In the final rule, EPA has eliminated the 100-hour limitation for emergency generators. Please refer to the full definition of emergency generator in §98.6.

Commenter Name: See Table 6
Commenter Affiliation:
Document Control Number: EPA-HQ-OAR-2008-0508-0679.1
Comment Excerpt Number: 80

Comment: HHV: Higher Heating Value or Gross Calorific Value. The quantity of heat produced by the complete combustion of a unit volume or weight of fuel assuming that the produced water is completely condensed (liquid state) and the heat is recovered.

Response: EPA believes that the proposed definition of high heat value is satisfactory, and has finalized this definition.

Commenter Name: Burl Ackerman
Commenter Affiliation: J. R. Simplot Company
Document Control Number: EPA-HQ-OAR-2008-0508-1641
Comment Excerpt Number: 12

Comment: Section 98.32 GHGs states, "You must report CO_2, CH_4, and N_2O mass emissions from each stationary fuel combustion unit." We recommend that a de minimis level be set for units not requiring reporting. We recommend that units which have a nameplate capacity less than 10 mmbtu/hr not be included in the report. To include every combustion source regardless of size, is an unreasonable reporting burden.

Response: See the Preamble, Section II. K., and the response to comment EPA-HQ-OAR-2008-0508-0423.2 excerpt 40 for the response on de minimis reporting for small emission points.

See the Preamble, Section II. E., and response to comment EPA-HQ-OAR-2008-0508-0350.1 excerpt 3 for additional explanation of the selection and form of thresholds.

EPA appreciates the commenter's concern. The final rule includes further clarification and flexibility regarding aggregation and common pipe provisions that will reduce the burden on sources. First, in order to reduce the burden of compliance, EPA has explicitly allowed for the use of company records to determine fuel consumption. EPA has also removed the cumulative 250 mmBtu/hr restriction on unit aggregation, and has clarified the common pipe reporting option. In §98.30, EPA has expanded the list of sources excluded from coverage; however, this expansion does not include a 10 mmBtu/hr exemption threshold, and such activities would be included under Subpart C for facilities that are required to comply with Part 98.

Commenter Name: Steven J. Rowlan
Commenter Affiliation: Nucor Corporation (Nucor)
Document Control Number: EPA-HQ-OAR-2008-0508-0605.1
Comment Excerpt Number: 41

Comment: In 98.30, an additional exclusion should be created at (c) for any unit, the methodology for which is set forth in Subparts D through PP to avoid double counting. For example, an EAF is listed in Subpart Q, but also combusts natural gas and/or other fuels, and hence would also appear to be subject to calculation under Subpart C.

Response: EPA intends that the stationary combustion source category include any device that meets the definition included in §98.30 for which emissions are not accounted for in the report through a separate subpart of the rule. Per the requirements in 40 CFR Part 98, Subpart A, facilities have to report GHG emissions from all source categories located at their facility, including stationary combustion and process emissions. EPA does not intend that emissions be double reported, and has revised the various subparts of the final rule to clarify the intent of the stationary combustion source category.

Commenter Name: Steven D. Meyers
Commenter Affiliation: General Electric Company (GE)
Document Control Number: EPA-HQ-OAR-2008-0508-0532.1
Comment Excerpt Number: 7

Comment: As an example of the confusing nature of the rule, the following question has been raised within GE concerning the applicability of the stationary source combustion category: Are GHG emissions from all fuels combusted by stationary combustion units including boilers, space heaters, dryers, furnaces, etc. included in the stationary source category?

Response: Subpart C excludes portable equipment, emergency generators and emergency equipment as defined in §98.6, irrigation pumps at agricultural operations, and flares, unless otherwise required by provisions of another subpart of Part 98 to use methodologies in this subpart. Other devices are included subject to the requirements of specific Tiers. EPA has revised the rule to clarify the applicability of the general stationary combustion source category. For units that have a maximum rated heat input capacity less than 250 mmBtu/hr and are not required to use Tier 4, only emissions from those fuels for which emission factors are provided need to be reported. Emissions from fuels for which emission factors are not provided only need to be reported if CEMS are used or the fuel provides ten percent or more of the annual heat input to a unit with a maximum rated heat input capacity greater than 250 mmBtu/hr or a group of units served by a common pipe. CH_4 and N_2O emissions only need to be reported for units that are required to report CO_2 emissions under Subpart C and for fuels for which default emission factors are provided.

The final rule includes further clarification and flexibility regarding aggregation and common pipe provisions that may also reduce the burden on sources. First, in order to reduce the burden of compliance, EPA has explicitly allowed for the use of company records to determine fuel consumption. EPA has also removed the cumulative 250 mmBtu/hr restriction on unit aggregation, and has clarified the common pipe reporting option.

2. REPORTING THRESHOLD

Commenter Name: See Table 5
Commenter Affiliation:
Document Control Number: EPA-HQ-OAR-2008-0508-0480.1
Comment Excerpt Number: 42

Comment: The Proposed Rule does not include de minimis emission levels or exemption for small combustion sources that are not required to have a permit issued by a state or local air pollution control agency, and the rule notes that the burden associated with reporting small sources is addressed. Despite this claim, INGAA believes that unwarranted burden will be imposed and recommends that a de minimis or size-based exemption threshold be identified for combustion sources. INGAA recommends a 10 MMBtu/hr exemption threshold. Many subject facilities include small combustors with minimal emissions. For example, water heaters at a small co-located office building and other small heaters will typically be present at subject facilities with much larger combustion sources. Typically, emissions will be inconsequential but activity data associated with these source types will not be readily available. Thus, an unnecessary amount of time will be spent devising fuel use or operating time estimates that will be highly uncertain and have an insignificant affect on facility emissions. Affected sources are faced with significant implementation challenges due to the breadth and timing of the Proposed Rule, and the additional burden associated with reporting trivial emissions is not warranted. INGAA recommends that a 10 MMbtu/hour exemption threshold be included in the rule for combustion sources.

Response: See the Preamble, Section II. K., and the response to comment EPA-HQ-OAR-2008-0508-0423.2 excerpt 40 for the response on de minimis reporting for small emission points.

EPA appreciates the commenter's concern. The final rule includes further clarification and flexibility regarding aggregation and common pipe provisions that will reduce the burden on sources. First, in order to reduce the burden of compliance, EPA has explicitly allowed for the use of company records to determine fuel consumption. EPA has also removed the cumulative 250 mmBtu/hr restriction on unit aggregation, and has clarified the common pipe reporting option. In §98.30, EPA has expanded the list of sources excluded from coverage; however, this expansion does not include a 10 mmBtu/hr exemption threshold. These sources would be included under Subpart C for facilities that are required to comply with Part 98.

Commenter Name: Matthew Frank
Commenter Affiliation: Wisconsin Department of Natural Resources
Document Control Number: EPA-HQ-OAR-2008-0508-1062.1
Comment Excerpt Number: 23

Comment: Reporting requirements clearly require submittal to EPA. It is not clear how soon State agencies would have access to the reports. Reports should be provided to the States at the same time as they are submitted to EPA.
Response: See the Preamble, Section II. O., "General Requirements of the Rule -- Summary of Comments and Responses on the Role of States and Relationship of this Rule to Other

Programs" and separate comment response document volume for the response on the relationship of this rule to other programs, and on the collection, management, and dissemination of GHG emissions data.

Commenter Name: Juanita M. Bursley
Commenter Affiliation: GrafTech International Holdings Inc. Company (GrafTech)
Document Control Number: EPA-HQ-OAR-2008-0508-0686.1
Comment Excerpt Number: 18

Comment: GrafTech agrees with the rationale used and conclusions reached by EPA to select the 25,000 metric tons/year CO_2e as the appropriate reporting threshold for stationary fuel combustion equipment.

Response: See the Preamble and separate comment response document volume for the response on selection of the threshold.

EPA appreciates this comment and intends to finalize the 25,000 metric tons CO_2e per year reporting threshold as proposed.

Commenter Name: David R. Case
Commenter Affiliation: Environmental Technology Council (ETC)
Document Control Number: EPA-HQ-OAR-2008-0508-0664.1
Comment Excerpt Number: 3

Comment: We do not believe that the 25,000 metric ton threshold for general stationary fuel combustion sources is appropriate for hazardous waste incinerators. We urge EPA to adopt a 100,000 metric ton threshold for these facilities. Since the 25,000 ton threshold is based on gross emissions, and does not consider net emissions resulting from destruction of CO_2e, at least a 100,000 ton threshold would provide some indirect consideration of this unique characteristic of hazardous waste incinerators. In addition, the hazardous waste sector is at most a very small contributor to overall CO_2e emissions from industrial sources. Even though individual incinerators may exceed the 25,000 ton threshold on a gross basis, the number of hazardous waste incinerators is sufficiently small to make emissions from these sources negligible.

Response: EPA acknowledges the concerns of the commenter, but has retained the 25,000 ton threshold in the final rule. See the Preamble, Section II. E., "General Requirements of the Rule -- Summary of Comments and Responses on Thresholds" for the response on the selection of the threshold. From analyses of available data, we concluded that a 25,000 metric ton threshold suited the needs of the reporting program by providing comprehensive coverage of emissions with a reasonable number of reporters, thereby creating the robust data set necessary for the quantitative analyses of the range of likely GHG policies, programs and regulations. We considered higher and lower thresholds, and determined that the intermediate options between 25,000 and 100,000 metric tons would not provide a point that significantly reduced the number of the reporters or substantially increased the cost effectiveness.

The commenter should consult §98.30 of the final rule, which EPA has revised to provide an expanded list of sources exempted from GHG emissions reporting under Subpart C, including in certain cases hazardous waste incinerators. It is EPA's intent that sources allowed to use the Tier 1 and 2 methods, which include smaller combustion devices and should be inclusive of control devices such as thermal oxidizers, will only be required to report emissions from the combustion of fuels for which emission factors are provided. In the Preamble, EPA has explained that "EPA believes that the reporting requirements for Tier 1 and Tier 2 would only require the reporting of GHG emissions from supplementary traditional fossil fuels from devices such as thermal oxidizers, pollution control devices, fume incinerators, burnout furnaces, and other such equipment."

Commenter Name: Linda Farrington
Commenter Affiliation: Eli Lilly and Company (Lilly)
Document Control Number: EPA-HQ-OAR-2008-0508-0680.1
Comment Excerpt Number: 27

Comment: The quantity of biomass or biomass derived fuel is easily distinguished from the fossil fuels combusted in a boiler; however, this does not hold true for industrial solid waste incinerators. Consequently, the requirement to report biogenic CO_2 emissions creates a much higher burden for industrial solid waste incinerators than for boilers. For a unit that combusts municipal solid waste (MSW), an owner or operator is required to us the prescribed ASTM methods to determine the relative portions of biogenic and non-biogenic CO_2 emissions. To our knowledge, no such methods exist for industrial solid wastes. In order to report biogenic CO_2 emissions under the proposed rule, an owner or operator of an industrial solid waste incinerator would need to classify each individual waste stream as "biomass" or "non-biomass" or determine the relative % if the waste stream contains a mixture of both. This exercise will take a tremendous amount of time and effort for incinerators, such as Lilly's, that treat hundreds of different types of waste streams each year. Therefore, we request EPA limit the reporting of biogenic CO_2 emission to boilers, process heaters, and MSW incinerators only.

Response: The use of ASTM Methods D7459-08 and D6866-06a to determine biogenic CO_2 emissions has been expanded to include the combustion of other fuels with a biogenic portion besides municipal solid waste where CEMS are used; these methods can be used for industrial solid waste incinerators. Further, EPA refers the commenter to §98.33(e) that provides that reporting of CO_2 emissions from combustion of biomass is required only for those biomass fuels listed in Table C-1 of this section, unless emissions are measured using CEMS. Industrial solid waste is not a type of fuel found in Table C-1 of Subpart C Part 98, and therefore the reporting of biogenic CO_2 emissions from the combustion of industrial solid waste will only be required if the use of CEMS is required, e.g., pursuant to the Tier 4 provisions in §98.33(b)(4). The use of Tier 4 is required only when all six conditions specified in §98.33(b)(4)(ii)(A) through (F) are met by a stationary combustion unit or when a unit meets the conditions specified in §98.33 (b)(4)(iii)(A) through (C).

Commenter Name: Kelly R. Carmichael
Commenter Affiliation: NiSource
Document Control Number: EPA-HQ-OAR-2008-0508-1080.2
Comment Excerpt Number: 10

Comment: NiSource supports conclusion made by EPA in the Subpart C preamble discussions that the Stationary Fuel Combustion Sources should report GHG emissions only if they exceed the threshold of 25,000 metric tons of CO_2e for the calendar year.

Response: See the Preamble and separate comment response document volume for the response on selection of the threshold.

EPA appreciates this comment and intends to finalize the 25,000 metric tons CO_2e per year reporting threshold as proposed.

Commenter Name: Theresa Pfeifer
Commenter Affiliation: Metro Wastewater Reclamation District
Document Control Number: EPA-HQ-OAR-2008-0508-0574.1
Comment Excerpt Number: 2

Comment: Many wastewater treatment plants operate numerous stationary fuel combustion sources as defined in Subpart C, Section 98.30 of the proposed rule. Additional clarification is needed on the scope of the combustion units that must be included. The District recommends that sources of air emissions that are currently categorized as insignificant activities or are exempted from Title V Operating Permits also be exempted from the total facility emissions calculations under the proposed rule. Such sources might include, but are not limited to, individual gaseous fuel burning equipment below a specific rated design threshold (10 million British thermal units per hour (mmBtu/hr) in Colorado) used solely for heating buildings for personal comfort.

Response: See the Preamble, Section II. K., and the response to comment EPA-HQ-OAR-2008-0508-0423.2 excerpt 40 for the response on de minimis reporting for small emission points.

See also the individual source category section(s) of the Preamble and the source category comment response document(s) for the reponse on the source category-specific reporting requirements in Subparts C through PP. In particular, note that EPA is not preparing the final rule, including requiring reporting of the emissions from wastewater treatment under Subpart II at this time.

EPA has revised §98.30 of the final rule to clarify the definition of the general stationary fuel combustion source category and provide an expanded list of sources exempted from GHG emissions reporting under Subpart C; however, this exclusion does not set a 10 mmBtu/hr capacity threshold. EPA has also removed the cumulative 250 mmBtu/hr restriction on unit aggregation and clarified common supply pipe metering, and believes that the expanded availability of these options will reduce the reporting burden on facilities.

Commenter Name: Michael E. Van Brunt
Commenter Affiliation: Covanta Energy Corporation
Document Control Number: EPA-HQ-OAR-2008-0508-0548.1
Comment Excerpt Number: 1

Comment: The threshold for triggering reporting by EfW is not consistent with thresholds applied to other point sources with the EfW threshold being 5 to 7 time lower than other sources. The Proposed Rule assigns a 250 mmBtu/hr threshold for other sources but for some reason applies a 250 ton-per-day threshold to EfW facilities. As explained in the following table – this fuel firing rate is proportional to approximately 80 metric tons of fossil CO_2/day versus a range of 318 to 566 metric tons for fossil fuel sources. The EPA should note that stack fossil CO_2 emissions is only one aspect of the overall GHG impact of EfW. When avoided grid and landfill methane are factored in, EfW is a GHG mitigation technology, well recognized internationally, including by the Intergovernmental Panel on Climate Change and the World Economic Forum. Applying an artificially low threshold to EfW has two problems: 1) it is far lower than others for no scientific reason, and 2) it ignores the GHG mitigation aspects. The reporting requirements should recognize the GHG benefits of EfW. At a minimum, the threshold applied to EfW facilities for Tier 4 reporting must be consistent with the reporting threshold applied to other stationary fuel combustion sources. Under the Proposed Rule, tier 2 calculations may be used for stationary combustion units where the maximum rated heat input capacity is 250 mmBtu/hr or less; however, a different threshold of 250 tons/day is applied to units that combust MSW. Based on a nominal heat content of 5,000 Btu/lb, consistent with monthly calculated MSW heat content at over nearly 30 Covanta facilities, the 250 tons/day threshold is equivalent to 104 mmBtu/hr, less than half the standard applied to other stationary combustion units. Conversely, a 250 mmBtu/hr threshold applied to nominal MSW would translate into a mass rate threshold of approximately 600 tons/day per unit. [See DCN: EPA-HQ-OAR-2008-0508-0548.1 for data table comparing daily CO_2 emissions by fuel.]

Response: In the final rule, the threshold of 250 tons per day for units that combust MSW relates to the applicability of specific tiers and is not a trigger for reporting. A unit combusting greather than 250 tons per day of MSW must use Tier 4 only if each of the other requirements are met, including the pre-existence of installed CEMS that are required either by an applicable Federal or State regulation or the unit's operating permit. The threshold 25,000 metric ton per year threshold for triggering reporting applies equally to units combusting MSW and units combusting other fuels.

Both the 250 mmBtu/hr and 250 tons MSW/day are size determinations for considering large sources in other EPA programs (e.g., 40 CFR 60 Subpart Ea and Eb for Municipal Solid Waste Combustors) that also require CEMS and the associated infrastructure. These size determinations were not considered to be directly comparable, but rather to reflect consistency with other EPA programs.

Commenter Name: Robert P. Strieter
Commenter Affiliation: The Aluminum Association
Document Control Number: EPA-HQ–OAR-2008-0508-0350.1
Comment Excerpt Number: 3

Comment: In determining fuel combustion related reporting requirements for facilities, the Aluminum Association supports fuel specific emission thresholds for reporting. Each of the major combustion fuels under consideration has markedly differing CO_2 equivalent emissions rates. Coal has the highest rate of emissions per unit of energy, while natural gas is relatively low in emissions per unit of energy. EPA proposed a 30 million BTU reporting threshold for combustion units regardless of fuel type. As a result, natural gas combustion units will be required to address reporting at a lower emission threshold than coal fired units. We recommend that EPA adopt separate BTU reporting thresholds for each fuel type to eliminate this inequity. By adopting fuel-specific specific thresholds, the reporting requirements will be more equitable and will better reflect the carbon-intensity of reporting facilities.

Response: See the Preamble and separate comment response document volume for the response on selection of the threshold.

EPA acknowledges the concerns of the commenter, but will continue to use the 25,000 metric ton CO_2e threshold for facilities that only include stationary combustion equipment. The 30 mmBtu/hr provision, as described in the general provisions is not a separate threshold, but was provided to give guidance to smaller facilities that would not be subject to applicability determinations. EPA prefers a single number to give to potential reporters for simplicity. If EPA were to calculate such numbers for specific fuels, it would have to calculate them for each possible fuel used in stationary combustion units, likely increasing uncertainty about applicability rather than decreasing it. EPA plans to publish additional guidance, as feasible, on equipment capacities, production levels, or other parameters that correlate with emissions of 25,000 metric tons per year of CO_2e.

Commenter Name: Steven J. Rowlan
Commenter Affiliation: Nucor Corporation (Nucor)
Document Control Number: EPA-HQ-OAR-2008-0508-0605.1
Comment Excerpt Number: 42

Comment: In 98.31, it is not clear what purpose this section serves since applicability is set in 98.2. This is true of all sections 98.x1 throughout the rule.

Response: EPA believes that it is appropriate to include §98.31 in the final rule, since this section provides clarification regarding which sources are required to report under Subpart C. Note also that the final version of this section refers directly to the facility applicability requirements defined in §98.2(a).

3. GHGS TO REPORT

Commenter Name: Jeffry C. Muffat
Commenter Affiliation: 3M Company
Document Control Number: EPA-HQ-OAR-2008-0508-0793.1
Comment Excerpt Number: 12

Comment: The emission factors for methane and nitrous oxide are shown in Table C-3 for common fuels and certain wastes only, and it is not clear how to report these emissions if the materials burned in the facility are not included in this Table. EPA stated in the Technical Support Document for this Subpart that methane and nitrous oxide account for less than one percent of the carbon dioxide equivalents. Technical Support Document for Stationary Fuel Combustion Emissions: Proposed Rule for Mandatory Reporting of Greenhouse Gases Office of Air and Radiation (U.S. Environmental Protection Agency, January 30, 2009), section 1.1. Since greater than 99% of the greenhouse gas emissions for this sector are covered by reporting carbon dioxide, little additional accuracy would be gained by reporting methane and nitrous oxide emissions. In addition, hazardous waste incinerators are required to destroy 99.99% of the organic material fed, including materials that are very difficult to destroy. Since methane is very easy to destroy, it is highly unlikely that any methane will be emitted from these facilities. Furthermore, there is very little, if any, information on nitrous oxide emissions for incinerators, including hazardous waste incinerators. Nitrous oxide emissions are not measured during required testing for incinerators. Information in current technical literature indicates the nitrous oxide emissions from high temperature combustion are very small. ("Until a few years ago, fuel combustion was thought to be a major source of nitrous oxide emissions. However, the discovery of a sampling error, which resulted in erroneously high emissions factors, revealed that combustion is actually a minor anthropogenic source." Department of Energy website: (http://www.eia.doe.gov/oiaf/1 605/archive/87-92rpt/chap4.html – accessed 4/20/09). This conclusion is also echoed in the TSD for this Subpart where EPA states: "The stationary combustion of carbon-based fuels produces three significant greenhouse gases: carbon dioxide (CO_2), methane (CH_4) and nitrous oxide (N_2O). The amount of CO_2 emitted is directly related to the carbon content of the fuel. Typically, nearly 100 percent of the fuel carbon is oxidized to CO_2. The CH_4 and N_2O emissions from stationary combustion are much smaller and are indirectly related to the carbon and nitrogen contents of the fuel. In the U.S., CO_2 emissions represent over 99 percent of the total CO_2-equivalent (CO_2e) GHG emissions from all commercial, industrial, and electricity generation stationary combustion sources. CH_4 and N_2O emissions together represent less than one percent of the total CO_2e emissions from the same sources (U.S. EPA, 2008 - Inventory of U.S. Greenhouse Gases and Sinks)." Research on nitrous oxide formation or destruction during the combustion processes gives the same picture. In a 1989 paper, it is stated that "N_2O is a very short-lived species in hot combustion gases..." Miller, J.A. and C.T. Bowman, 1989, Mechanism and Modeling of Nitrogen Chemistry in Combustion, Prog. Energy Combust. Sci., Vol. 15:287-33 8, p. 324). In a subsequent article, Miller and Bowman state, "At low temperatures, the N_2O is relatively stable and appears as a major product in the gas stream; however, at temperatures above 1150 K, the calculations show that N_2O decays rapidly in the gas stream and is still decomposing at the exit of the reactor..." Miller, J.A. and C.T. Bowman, 1991. Kinetic Modeling of the Reduction of Nitric Oxide in Combustion Products by Isocyanic Acid, International Journal of Chemical Kinetics, Vol 23: 289-313, p. 310. The 1150 K temperature mentioned in the quote corresponds to approximately 1600 °F, slightly lower than the temperatures in most hazardous waste combustors. In addition, the authors state that nitrous oxide decays rapidly in gas-phase temperatures above 1150 K. (p. 310). Finally, in his book Principles of Combustion, Kuo states that N_2O formed during combustion reacts rapidly with hydrogen ions to form N_2. Kuo, K.K. 2005, Principles of Combustion, John Wiley & Sons, Inc. (p. 268). Development of emission factors for methane and nitrous oxide emissions for hazardous waste incinerators will be onerous for those incinerators which burn a significant number of waste streams. 3M has thousands of active waste streams all with a slightly different profile. In addition, testing for these compounds will be costly and is not likely to show a significant quantity of such emissions based on the literature described above. 3 M requests that EPA exempt hazardous waste incinerators from the scope of Subpart C.

Response: EPA acknowledges the concerns of the commenter. Section 98.33(c) of the final rule excludes CH_4 and N_2O emissions from fuels that are not listed in Table C-2 from calculation. Table C-2 has been revised to include generic CH_4 and N_2O emission factors covering all fuel types listed in Tables C-1. In addition, the rule includes instructions for estimating CH_4 and N_2O emissions from MSW. However, EPA has deleted from §98.33(c) instructions which prescribed methods for facilities burning other fuels to develop site-specific emission factors based on the results of source testing. Finally, hazardous waste incinerators that do not combust any supplemental fuels are excluded from the stationary combustion source category in §98.30. Only emissions from supplemental fuels combusted in these units must be reported. Furthermore, it is EPA's intent that sources allowed to use the Tier 1 and 2 methods, which include smaller combustion devices and should be inclusive of control devices such as thermal oxidizers, will only be required to report emissions from the combustion of fuels for which emission factors are provided. In the Preamble, EPA has explained that "EPA believes that the reporting requirements for Tier 1 and Tier 2 would only require the reporting of GHG emissions from supplementary traditional fossil fuels from devices such as thermal oxidizers, pollution control devices, fume incinerators, burnout furnaces, and other such equipment."

Commenter Name: Traylor Champion
Commenter Affiliation: Georgia-Pacific, LLC (GP)
Document Control Number: EPA-HQ-OAR-2008-0508-0380.1
Comment Excerpt Number: 24

Comment: Throughout the reporting rule EPA indicates that emissions of biogenic CO_2 are to be calculated and reported separately, but are not to be included in the threshold determination. GP agrees with EPA that biogenic CO_2 emissions should not be included in the calculations for comparison to the reporting threshold. GP further believes that biogenic CO_2 emissions should not be required to be reported. It is widely accepted that biogenic CO_2 emissions are carbon neutral because the carbon in the biomass is part of the natural carbon cycle. Not reporting biogenic CO_2 emissions is consistent with the Department of Energy (DOE) Technical Guidelines and the European Union Emissions Trading Scheme. In addition, current prospective climate change legislation does not address or include emissions from biomass. One purpose of the proposed reporting rule is to provide data to be used in potential future GHG emission control programs. Given that these programs will not include biogenic CO_2 emissions, reporting of these emissions under this proposed rule is not warranted.

Response: See the response to comment EPA-HQ-OAR-2008-0508-0690.1 excerpt 1 corresponding to Section II. of the Preamble, and the response to comment EPA-HQ-OAR-2008-0508-0631.1 excerpt 71 corresponding to Subpart C for additional explanation of the reporting of biogenic CO_2 emissions.

EPA appreciates the comment, but has retained the mandatory requirement for reporting of biogenic CO_2 emissions in the final rule. Including reporting of biogenic CO_2 at facilities that are already reporting for stationary combustion provides EPA with information on the use of biofuels as they relate to reductions of fossil CO_2 emissions over time. This reporting requirement also provides additional data for verification. EPA believes that it is clear in §98.2 that CO_2 emissions from biogenic fuels do not count toward the 25,000 metric ton threshold for reporting, although CH_4 and N_2O emissions from biogenic fuels must be considered.

Commenter Name: Thomas M. Ward
Commenter Affiliation: Novelis Corporation
Document Control Number: EPA-HQ-OAR-2008-0508-0561.1
Comment Excerpt Number: 1

Comment: The proposed rule speaks up front to facility-level reporting which for such a rule is reasonably well received. However, in the detail of the rule the requirements actually demand source unit measurement and reporting unless an aggregation is available and with the aggregation there is a high level of complexity and restriction in the rule that would almost certainly be augmented by challenges at the facility to monitor and report.

Response: See the Preamble and the response to comment EPA-HQ-OAR-2008-0508-0520.1 excerpt 16 for the response indicating the additional flexibility provided to reporters, particularly for common pipe and aggregated unit circumstances.

EPA appreciates the commenter's concerns. Reporting at the unit level has a number of benefits, including greatly increasing the ability of EPA to verify data and not require third party verification. EPA has made a number of significant adjustments in the final rule to the data reporting requirements of §98.36, both to clarify those requirements and to reduce the reporting burden at the unit level.

First, for units that use Tiers 1, 2, and 3 to calculate CO_2 mass emissions, the cumulative 250 mmBtu/hr heat input capacity limit on the aggregation of units into a group has been dropped. Rather, the 250 mmBtu/hr restriction applies only to the individual units in the group. Therefore, for reporting purposes, individual units with maximum rated heat input capacities of 250 mmBtu/hr or less may be aggregated without limit into a single group, provided that the Tier 4 Calculation Methodology is not required for any of the units, and all units in the group use the same tier for any common fuel(s) that they combust. Units with maximum rated heat inputs greater than 250 mmBtu/hr must report as individual units, unless they burn the same type of fuel provided by a common pipe or supply line; in that case, the owner or operator may opt to use the common pipe reporting provisions in §98.36(c)(3). Units using Tier 4 must report as individual units unless they share a monitored common stack or duct; in that case, the common stack or duct reporting provisions of §98.36(c)(2) may be used.

Second, §98.36(d) specifically addresses units that are required to monitor and report emissions and heat input data according to Part 75. This includes units that are subject to the Acid Rain Program, CAIR, and RGGI. The unit-level data required for these sources is minimal, consisting primarily of the GHG emissions totals at each monitored location (i.e., unit, stack, or pipe).

Commenter Name: Thomas M. Ward
Commenter Affiliation: Novelis Corporation
Document Control Number: EPA-HQ-OAR-2008-0508-0561.1
Comment Excerpt Number: 2

Comment: Given the low contribution from emissions of the non-CO_2 GHG gases, EPA should recognize the low value of this additional reporting and thereby consider elimination of the requirement for reporting of these other gases from the stationary combustion sources.

Response: CH_4 and N_2O are covered under the UNFCCC, are emitted from stationary sources that would report under Subpart C, and while the national greenhouse gas inventory tracks overall trends of these emissions, this reporting requirement will provide EPA with valuable additional information relating to these gases such as trends over time in specific industries. Emissions data at the facility level for CH_4 and N_2O are also useful for researchers who need to know where the gases are emitted. EPA is also seeking information to make informed decisions regarding whether, what and how to address GHG emissions from particular sectors. While EPA may not end up addressing CH_4 and N_2O from boilers in a standard or a program, the Agency needs the information to make an informed decision. EPA believes that the use of fuel-specific emission factors for these pollutants strikes an appropriate balance between minimizing the burden on reporters and obtaining valuable GHG emission data. EPA has, however, revised the final rule to exclude CH_4 and N_2O emissions from fuels for which the rule does not provide emission factors, and has deleted the provision allowing the owner or operator of a facility to develop site-specific emission factors for such fuels. EPA believes that this change will reduce the reporting burden on facilities.

Commenter Name: Filipa Rio
Commenter Affiliation: Alliance of Automobile Manufacturers (Alliance)
Document Control Number: EPA-HQ-OAR-2008-0508-0630.1
Comment Excerpt Number: 20

Comment: CO_2, CH_4, and N_2O emissions are required to be reported from all stationary fuel combustion activities. The Alliance recommends that CH_4 and N_2O emissions be excluded from stationary fuel combustion source reporting. Emissions of these particular gases are relatively low when compared to CO_2 and require a disproportionate effort to estimate and report. In fact, the DOE notes in the Technical Guidelines for the Voluntary Reporting of Greenhouse Gases (1605(b)) Program that "stationary source combustion also produces trace quantities of methane and nitrous oxide." The Technical Guidelines state that "95 to 99 percent of global warming potential-weighted emissions from stationary source combustion are usually attributed to carbon dioxide." Several other prominent technical resources such as the World Resources Research Institute/World Business Council for Sustainable Development "WRIM/BCSD Greenhouse Gas

Protocol" indicate CH_4 and N_2O emissions from stationary combustion are generally minor, on a CO_2e basis, compared to O2. While EPA has proposed simpler calculation methods for these gases, the emission rates for CH_4 and N_2O are much less predictable as they are by-products of incomplete or inefficient combustion, and depend on many factors such as combustion technology and other considerations. The potential inaccuracies of reporting CH_4 and N_2O emissions based upon a simplified approach may not be worth the additional effort required by reporters based on the trace amount of emissions. This concept has been endorsed by several existing GHG reporting programs including the Regional Greenhouse Gas Initiative ("RGGI") and the EU ETS.

Response: CH_4 and N_2O are covered under the UNFCCC, are emitted from stationary sources that would report under Subpart C, and while the national greenhouse gas inventory tracks overall trends of these emissions, this reporting requirement will provide EPA with valuable additional information relating to these gases such as trends over time in specific industries. Emissions data at the facility level for CH_4 and N_2O are also useful for researchers who need to know where the gases are emitted. EPA is also seeking information to make informed decisions regarding whether, what and how to address GHG emissions from particular sectors. While EPA may not end up addressing CH_4 and N_2O from boilers in a standard or a program, the Agency needs the information to make an informed decision. EPA believes that the use of fuel-specific emission factors for these pollutants strikes an appropriate balance between minimizing the burden on reporters and obtaining valuable GHG emission data. EPA has, however, revised the final rule to exclude CH_4 and N_2O emissions from fuels for which the rule does not provide emission factors, and has deleted the provision allowing the owner or operator of a facility to develop site-specific emission factors for such fuels. EPA believes that this change will reduce the reporting burden on facilities.

Commenter Name: Jeff A. Myrom
Commenter Affiliation: MidAmerican Energy Holdings Company
Document Control Number: EPA-HQ-OAR-2008-0508-0581.1
Comment Excerpt Number: 30

Comment: EPA should not include CH_4 and N_2O emissions from combustion because such emissions are too small, variable, and technology dependent to add material value to the emissions inventory. For example, EPA states that CH_4 emissions are equivalent to 0.03% of CO_2e emissions per ton of coal, and N_2O emissions are equivalent to 0.4% of CO_2e emissions per ton of coal. Regarding natural gas combustion, CH_4 emissions are equivalent to 0.1% of CO_2e emissions, and N_2O emissions equivalent to 0.1% of CO_2e emissions. In no other portion of the proposed rule does EPA propose including such uncertain and negligible emissions. Thus, to aid EPA, GHG emissions reporters, and the quality of the emissions inventory, CH_4 and N_2O estimated emissions from any combustion process should be removed as a reporting requirement for all facilities and suppliers.

Response: CH_4 and N_2O are covered under the UNFCCC, are emitted from stationary sources that would report under Subpart C, and while the national greenhouse gas inventory tracks overall trends of these emissions, this reporting requirement will provide EPA with valuable additional information relating to these gases such as trends over time in specific industries. Emissions data at the facility level for CH_4 and N_2O are also useful for researchers who need to know where the gases are emitted. EPA is also seeking information to make informed decisions regarding whether, what and how to address GHG emissions from particular sectors. While EPA may not end up addressing CH_4 and N_2O from boilers in a standard or a program, the Agency needs the information to make an informed decision. EPA believes that the use of fuel-specific emission factors for these pollutants strikes an appropriate balance between minimizing the burden on reporters and obtaining valuable GHG emission data. EPA has, however, revised the final rule to exclude CH_4 and N_2O emissions from fuels for which the rule does not provide emission factors, and has deleted the provision allowing the owner or operator of a facility to develop site-specific emission factors for such fuels. EPA believes that this change will reduce the reporting burden on facilities.

Commenter Name: Paul Dubenetzky
Commenter Affiliation: KERAMIDA Inc.
Document Control Number: EPA-HQ-OAR-2008-0508-0419.1
Comment Excerpt Number: 12

Comment: KERAMIDA appreciates that the U.S. EPA has proposed that sources aggregate small emission units into groups for the purposes of reporting GHG emissions. However, we believe that requiring that the total aggregate heat capacity of each group not exceed 250 mniBtu/hr is arbitrary and serves no useful purpose. Facilities that have multiple, small emissions units should not be required to separately account for emissions based solely on the combined heat input capacity rating. An additional "sub-metering" requirement is a burden to reporters that provides no additional useful information to the U.S. EPA or to the public.

Response: EPA appreciates the commenter's concern and has made several revisions to the final rule. For units that use Tiers 1, 2, and 3 to calculate CO_2 mass emissions, the cumulative 250 mmBtu/hr heat input capacity limit on the aggregation of units into a group has been dropped. Rather, the 250 mmBtu/hr restriction applies only to the individual units in the group. Therefore, for reporting purposes, individual units with maximum rated heat input capacities of 250 mmBtu/hr or less may be aggregated without limit into a single group, provided that the Tier 4 methodology is not required for any of the units, and all units in the group use the same tier for any common fuel(s) that they combust. Units with maximum rated heat inputs greater than 250 mmBtu/hr using Tiers 1, 2, and 3 must report as individual units, unless they burn the same type of fuel provided by a common pipe or supply line; in that case, the owner or operator may opt to use the common pipe reporting provisions in §98.36(c)(3). Units using Tier 4 must report as individual units unless they share a monitored common stack or duct; in that case, the common stack or duct reporting provisions of §98.36(c)(2) may be used.

Commenter Name: Renae Schmidt
Commenter Affiliation: CITGO Petroleum Corporation
Document Control Number: EPA-HQ-OAR-2008-0508-0726.1
Comment Excerpt Number: 8

Comment: CITGO agrees with the tiered approach for fuel combustion sources and that most of the requirements for this category are reasonable. CITGO disagrees with the reporting for CH_4

and N_2O within the Combustion Sources and some Petroleum Refinery source categories. Rather, greenhouse gases resulting from combustion sources or processes for the Petroleum Refinery source category should be reported on a CO_2e basis rather than CO_2, N_2O, and CH_4 separately. CH_4 and N_2O greenhouse gas contributors are insignificant when compared to the CO_2 emissions and, as such, should be combined into a single emission factor for calculating and reporting purposes. As an example, the default factor for natural gas is 102.04 while the default values for CH_4 and N_2O are 9.0 x 10-4and 1.0 x 10-4, respectively. If one then applies the global warming potential, the CO_2e equivalent can be shown as follows: [See DCN: EPA-HQ-OAR-2008-0508-0726.1 for CO_2, CH_4 and N_2O Contribution to Combustion CO_2e from Natural Gas Combustion table] Similar calculations apply to other fuels used within a refinery. In summary, CITGO believes that greenhouse gas emission reporting should be on CO_2e basis for all combustion sources including cat cracker coke combustion. It is both unreasonable and unnecessary to track, calculate, and report every greenhouse gas separately as though the inventory were a speciation exercise when it is, in fact, an inventory. Measurement error alone for the combustion sources and cat cracker coke burns significantly exceed the contributions of either CH_4 and/or N_2O combustion contribution. For example, orifice meters typically have 1 - 3% accuracy, depending on use and process conditions - well above the CH_4 and N_2O contribution. For complex refineries with dozens of combustion sources, setting up and verifying additional (and unnecessary) calculations in a database or spreadsheet is time consuming, expensive, and wasteful. The nearly nonexistent return relative to the value of information gleamed on the time invested to generate it justifies the Agency's application of a rational "cutoff' for such insignificant emissions, if any. In addition, these extra calculations steps can often result in error due to extra configuration of a database or spreadsheet. CITGO urges EPA to keep reporting simple as possible and to focus on calculation and measurement accuracy for the inventory, not insignificant contribution breakout of CH_4 and N_2O. In the end, the reporting of GHG emissions as CO_2e will have little, if any, bearing on any future reduction program.

Response: Reporting gases individually increases transparency, provides atmospheric researchers who are concerned with actual radiative forcing individual gases more useful data for their work, and allows EPA to retroactively apply updated GWPs more easily should they need to be updated per international standards. To this end, EPA has also decided to retain the separate emission factors and calculations for CH_4 and N_2O. EPA believes that using fuel-based default emission factors to report these gases separately provides an appropriate balance between easing the reporting burden on facilities and collecting useful data on GHG emissions.

Commenter Name: Karen St. John
Commenter Affiliation: BP America Inc. (BP)
Document Control Number: EPA-HQ-OAR-2008-0508-0631.1
Comment Excerpt Number: 57

Comment: Section 98.32 states: "You must report CO_2, CH_4, and N_2O mass emissions from each stationary fuel combustion unit." This could be read to mean that all emissions must be reported on an individual unit basis rather than the other options afforded in Subpart C. BP requests that EPA clarify the requirement in Subpart C as an inclusive scope rather than a reporting form requirement.

Response: In the final rule, CO_2, CH_4, and N_2O mass emissions from each stationary fuel combustion unit must be reported separately, by unit, if the calculations are done at the unit level. This requirement is necessary for transparency and verification purposes. If an aggregated unit, common pipe, or common stack approach is used, then CO_2, CH_4, and N_2O mass emissions can be reported collectively for the applicable units.

Commenter Name: Craig S. Campbell
Commenter Affiliation: Lafarge North America
Document Control Number: EPA-HQ-OAR-2008-0508-0674.1
Comment Excerpt Number: 15

Comment: Proposed 40 CFR §98.33(c) requires calculation of methane (CH_4) and nitrous oxide (N_2O) emissions from all stationary combustion units. As documented in the WBCSD CO_2 Cement protocol, cement industry data indicate that CH_4 emissions are typically about 0.01% of kiln CO_2 emissions in a CO_2e basis, and N_2O emissions are also very small. Consequently, the WBCSD protocol does not require inclusion of these de minimis emissions. There would be little if any value of collecting data on these two pollutants, since their CO_2-equivalent emissions would be an insignificant fraction of the total CO_2e emissions from the cement facility and would be less than the confidence interval around the CO_2e emissions calculated without accounting for CH_4 and N_2O. In light of their de minimis nature, Lafarge recommends that cement kilns not be required to calculate and report CH_4 and N_2O.

Response: CH_4 and N_2O are covered under the UNFCCC, are emitted from stationary sources that would report under Subpart C, and while the national greenhouse gas inventory tracks overall trends of these emissions, this reporting requirement will provide EPA with valuable additional information relating to these gases such as trends over time in specific industries. Emissions data at the facility level for CH_4 and N_2O are also useful for researchers who need to know where the gases are emitted. EPA is also seeking information to make informed decisions regarding whether, what and how to address GHG emissions from particular sectors. While EPA may not end up addressing CH_4 and N_2O from boilers in a standard or a program, the Agency needs the information to make an informed decision. EPA believes that the use of fuel-specific emission factors for these pollutants strikes an appropriate balance between minimizing the burden on reporters and obtaining valuable GHG emission data. EPA has, however, revised the final rule to exclude CH_4 and N_2O emissions from fuels for which the rule does not provide emission factors, and has deleted the provision allowing the owner or operator of a facility to develop site-specific emission factors for such fuels. EPA believes that this change will reduce the reporting burden on facilities.

Commenter Name: Marc J. Meteyer
Commenter Affiliation: Compressed Gas Association (CGA)
Document Control Number: EPA-HQ-OAR-2008-0508-0981.1
Comment Excerpt Number: 20

Comment: The preamble for the proposed rule states that CO_2 emissions far exceed the CO_2-e contributions of combustion byproduct emissions of CH_4 and N_2O, specifically "less than 1 percent of combined U.S. GHG emissions from stationary combustion, on a CO_2-e basis." Despite this insignificant contribution, combustion sources are being required to estimate these emissions. In some instances, particularly where the lower tier methods for calculating CO_2 emissions are employed, the calculation of combustion byproduct CH_4 and N_2O is straightforward. But in instances where more rigorous methods for calculating CO_2 emissions are required (e.g. Tier 4), the calculation of combustion byproduct CH_4 and N_2O requires a completely separate calculation process (and inherent process measurement data), comparable to Tiers 1-3 for CO_2 emissions. This is a burdensome requirement for an insignificant contribution to a source's overall GHG footprint. CGA Comment: CGA does not support calculating the combustion byproduct CH_4 and N_2O. However, if the agency feels these emissions are significant, it should allow greater use of Tiers 1, 2, and 3 for estimating CO_2 emissions (per comments on §98.33(b), above).

Response: CH_4 and N_2O are covered under the UNFCCC, are emitted from stationary sources that would report under Subpart C, and while the national greenhouse gas inventory tracks overall trends of these emissions, this reporting requirement will provide EPA with valuable additional information relating to these gases such as trends over time in specific industries. Emissions data at the facility level for CH_4 and N_2O are also useful for researchers who need to know where the gases are emitted. EPA is also seeking information to make informed decisions regarding whether, what and how to address GHG emissions from particular sectors. While EPA may not end up addressing CH_4 and N_2O from boilers in a standard or a program, the Agency needs the information to make an informed decision.

EPA believes that the use of fuel-specific emission factors for these pollutants strikes an appropriate balance between minimizing the burden on reporters and obtaining valuable GHG emission data. EPA has, however, revised the final rule to exclude CH_4 and N_2O emissions from fuels for which the rule does not provide emission factors, and has deleted the provision allowing the owner or operator of a facility to develop site-specific emission factors for such fuels. EPA believes that this change will reduce the reporting burden on facilities.

The Agency has clarified the requirements to report under Tier 4, and has made several changes to reporting dates, extensions, and exceptions, that may indirectly address these concerns. While the EPA does not find the methodologies for calculating CH_4 and N_2O emissions burdensome, the EPA has clarified in the final rule that reporting of these emissions is required only for the fuels listed in Table C-2 of Subpart C. When more than one type of fuel is combusted in a unit, direct measurements or engineering estimates of the annual heat input from each fuel are needed to calculate the CH_4 and N_2O emissions. Consequently, when CEMS (which are not fuel-specific) are used to monitor the CO_2 emissions and heat input for a multi-fuel unit, the total heat input measured by the CEMS must be apportioned to each fuel type. The owner or operator should use the best available information (e.g., fuel feed rates, GCV values, etc.) to do the necessary heat input apportionment.

Commenter Name: Marc J. Meteyer
Commenter Affiliation: Compressed Gas Association (CGA)
Document Control Number: EPA-HQ-OAR-2008-0508-0981.1
Comment Excerpt Number: 21

Comment: The proposed rule offers an equation for calculating the contribution of CO_2 emissions from flue gas desulfurization sorbents, equation C-1 1, which does not appear to be dimensionally (units) correct. Specifically, the "R" term in the equation appears to be incorrectly defined. CGA Comment: Insure the definitions of terms for equation C-1 1 are dimensionally correct.

Response: EPA has corrected this error in the final rule. The R term has been redefined as "1.00, the calcium-to-sulfur stoichiometric ratio."

Commenter Name: J. P. Blackford
Commenter Affiliation: American Public Power Association (APPA)
Document Control Number: EPA-HQ-OAR-2008-0508-0661.1
Comment Excerpt Number: 23

Comment: EPA distinguishes CO_2 and biogenic CO_2 emissions from stationary combustion sources. In the preamble, EPA notes that this distinction is consistent with international policy developed by the International Panel on Climate Change, California Air Resources Board Reporting Rule and European Union Emissions Trading System. APPA supports distinguishing CO_2 and biogenic CO_2. Electric generation facilities which are subject to the Acid Rain Program do not appear to have the opportunity to distinguish CO_2 from biogenic CO_2, since the proposed rule requires that total mass emissions be reported. APPA requests that electric generation facilities subject to the Acid Rain Program be allowed to report biogenic CO_2, consistent with other stationary combustion sources.

Response: It is EPA's intent that Acid Rain Program units will be able to continue to measure and report CO_2 emissions as they do under the Acid Rain Program. EPA believes that this will reduce the reporting burden on sources, and for this reason has not required Acid Rain Program units to report biogenic emissions separately. However, EPA has provided a method for Acid Rain Program units which choose to separately quantify their biogenic CO_2 emissions; see §98.33(e) of the final rule.

Commenter Name: Juanita M. Bursley
Commenter Affiliation: GrafTech International Holdings Inc. Company (GrafTech)
Document Control Number: EPA-HQ-OAR-2008-0508-0686.1
Comment Excerpt Number: 25

Comment: On page 16480 of the preamble, although EPA notes that CO_2 emission generated by fuel combustion far exceeds the CH_4 and N_2O emissions (< 1% of total), EPA nevertheless has proposed that facilities must also estimate and report emissions of these two lessor GHGs. While GrafTech agrees that all combustion GHGs should be accounted for in the national GHG database for accuracy, it supports the use of a combined $CO_2/CH_4/N_2O$ emission factor used by some of the internationally recognized GHG emissions estimating protocols. This would simplify the calculation methods and reduce the burden on reporting facilities, without significantly compromising the accuracy of the emissions data.

Response: Reporting gases individually increases transparency, provides atmospheric researchers who are concerned with actual radiative forcing individual gases more useful data for their work, and allows EPA to retroactively apply updated GWPs more easily should they need to be updated per international standards. EPA believes that the use of fuel-specific emission factors for these pollutants strikes an appropriate balance between minimizing the burden on reporters and obtaining valuable GHG emission data. EPA has, however, revised the final rule to exclude CH_4 and N_2O emissions from fuels for which the rule does not provide emission factors, and has deleted the provision allowing the owner or operator of a facility to develop site-specific emission factors for such fuels. EPA believes that this change will reduce the reporting burden on facilities.

Commenter Name: See Table 10
Commenter Affiliation:
Document Control Number: EPA-HQ-OAR-2008-0508-0635
Comment Excerpt Number: 53

Comment: We also request that EPA clarify in its final rule that power companies subject to reporting CO_2 emissions for Acid Rain Program units also must report SF_6 emissions. While EPA addresses SF_6 emissions in its proposal and proposes a separate reporting threshold, EPA should also specify that power companies with Acid Rain Program units are subject reporting obligations for SF_6. The "electric power industry uses roughly 80% of all SF_6 produced worldwide" through the transmission and distribution of electricity. Further, SF_6 is a highly potent greenhouse gas: With a global warming potential 23,900 times greater than CO_2 and an atmospheric life of 3,200, one pound of SF_6 has the same global warming impact of 11 tons of CO_2. In 2002, U.S. SF_6 emissions from the electric power industry were estimated to be 14.9 Tg CO_2 [e]. [footnote: See US EPA, http://www.epa.gov/electricpower-sf6/. Id.] EPA should therefore ensure that this important emissions source is covered in this context.

Response: EPA believes that it is made clear in §98.2 that the GHG emission report for facilities containing Acid Rain Program units must include emissions from all sources in any source category for which Calculation Methodologies are provided in Subparts B through JJ. However, at this time EPA is not going final with the electrical equipment subpart. See the Preamble section on Subpart DD for more information related to this decision.

Commenter Name: Chris Greissing
Commenter Affiliation: Industrial Minerals Association - North America (IMA-NA)
Document Control Number: EPA-HQ-OAR-2008-0508-0705.1
Comment Excerpt Number: 6

Comment: IMA-NA requests the elimination of CH_4 and N_2O calculations entirely due to their minimal impact on the total greenhouse gas inventory and on a facility's emissions. Based on the formulae provided, less than 0.00001 percent of the greenhouse gas emissions would be CH_4 or N_2O. EPA should not require calculation and reporting of these emissions because their contribution to the total is clearly insignificant.

Response: CH_4 and N_2O are covered under the UNFCCC, are emitted from stationary sources that would report under Subpart C, and while the national greenhouse gas inventory tracks overall trends of these emissions, this reporting requirement will provide EPA with valuable additional information relating to these gases such as trends over time in specific industries. Emissions data at the facility level for CH_4 and N_2O are also useful for researchers who need to know where the gases are emitted. EPA is also seeking information to make informed decisions regarding whether, what and how to address GHG emissions from particular sectors. While EPA may not end up addressing CH_4 and N_2O from boilers in a standard or a program, the Agency needs the information to make an informed decision.

EPA believes that the use of fuel-specific emission factors for these pollutants strikes an appropriate balance between minimizing the burden on reporters and obtaining valuable GHG emission data. EPA has, however, revised the final rule to exclude CH_4 and N_2O emissions from fuels for which the rule does not provide emission factors, and has deleted the provision allowing the owner or operator of a facility to develop site-specific emission factors for such fuels. EPA believes that this change will reduce the reporting burden on facilities.

4. SELECTION OF PROPOSED GHG EMISSIONS CALCULATION AND MONITORING METHODS

Commenter Name: Michael W. Stroben
Commenter Affiliation: Duke Energy Corporation
Document Control Number: EPA-HQ-OAR-2008-0508-0407.1
Comment Excerpt Number: 10

Comment: Most coal-fired sources which measure CO_2 using CEMS under Part 75 measure the total CO_2 and are not typically set up to distinguish between CO_2 (or other emissions) emitted by fuel type. Altering the CEMS to record heat input by fuel type would add significant cost without any real benefit, and does not seem to be necessary to fulfill the obligations under the legislative mandate. If EPA retains the requirement to show the heat input for each fuel, it should include procedures which would allow a reasonable estimate to be made of the GHG emissions related to a secondary fossil fuel. For example, the emissions related to oil use in a coal fired boiler for startup and other miscellaneous uses (such as flame stabilization) can be calculated based on total fuel consumption and the emission factors in Tables C-1 through C-3. This amount can be subtracted from the total heat input for a unit that exclusively burns fossil fuels. For a unit that co-fires biogenic fuels, the fuel specific CO_2 emissions can be derived from equations C-12 and C-13.

Response: EPA acknowledges the commenter's concerns, and has addressed this issue. EPA has added provisions to the final rule requiring units subject to Part 75 to report total emissions by unit, not by fuel. EPA believes that these provisions effectively address the concerns of the commenter

The final rule specifies that, for Tier 4 units, the annual CO_2 emissions will be reported for all fuels combined, and that any biogenic CO_2 emissions will also be reported separately. It also states that CH_4 and N_2O emissions are to be reported for each type of fuel combusted, calculated in accordance with §98.33(c). EPA has specified that reporters using Tier 4 are to calculate CH_4 and N_2O emissions for each fuel type using the best available estimates of the annual heat input from each type of fuel combusted in the unit during the reporting year. This can be from CEMS data or engineering calculations.

Commenter Name: Kerry Kelly
Commenter Affiliation: Waste Management (WM)
Document Control Number: EPA-HQ-OAR-2008-0508-0376.1
Comment Excerpt Number: 6

Comment: Consistent with the WCI and DOE GHG reporting rules, EPA's final MRR should eliminate the requirement that large MWCs use the Tier 4 methodology. The DOE 1605 (b) approach is very similar to the calculation methodology used for reporting annual emissions of criteria pollutants and HAPs as required by Title V operating permits. Each year MWC facilities must conduct multiple stack or performance tests (under NSPS Subpart Eb/Cb) on all MWC units, over several days using EPA Methods 1 - 29. Some MWC facilities stack test twice per year, as some state requirements are more restrictive than the federal standards. The DOE approach would take advantage of these extensive testing requirements. The modified Tier 2 methodology would utilize multiple stack results over several days as follows: (1) Calculate facility average CO_2 concentration (%), stack gas flow rate (DSCF/Hour) and boiler load or steam production (Klbs/hour); (2) calculate a Stack Flow to Load Ratio (SFLR) or DSCF/Hr per Klbs/hr steam production. The SFLR is analogous to the proposed Tier 2 "B" design heat input to steam ratio used in Equation C-2b, but could be considered more representative since it is based on actual test data; (3) obtain biogenic/non-biogenic CO_2 fractions using ASTM Methods D 7459 and D 6866-06a from integrated gas samples collected during stack testing; and (4) use CO_2 concentration, total steam production and SFLR to calculate MWC unit and facility wide annual CO_2 emissions. The above approach modifies the Tier 2 methodology slightly since actual CO_2 concentrations are used (not a fixed emission factor), and mass CO_2 emissions are calculated from actual stack gas flow and actual steam production rather than using a fixed design heat input. Table 2 [see DCN: EPA-HQ-OAR-2008-0508-0376.1] summarizes 2008 non-biogenic CO_2 emissions from WM Wheelabrator large (i.e., greater than 250 tpd) MWC facilities calculated in accordance with the proposed alternative methodology. See DCN: EPA-HQ-OAR-2008-0508-0376.1 for a proposed third equation to Tier 2 Calculation Methodology. We recommend that the ASTM D6866-06a non-biogenic carbon fraction results be directly included in the calculation methodology for Municipal Solid Waste combustion. This will improve transparency in reporting GHG CO_2 emissions and eliminate potential for error in apportioning non-biogenic and biogenic CO_2 emission.

Response: EPA believes that it is appropriate to require the use of CEMS on the largest MSW combustion sources and any smaller MSW combustion source which already has CO_2 concentration monitors and stack gas volumetric flow rate monitors in place. EPA has, however, clarified that all of the criteria in §98.33(b)(4)(ii) or (iii) must be present to require the use of Tier 4. EPA believes that it is appropriate for MSW combustion units to use ASTM D6866-06a and D7459-08 on a quarterly basis to determine the relative proportions of biogenic and non-biogenic CO_2 emissions from the MSW combusted. Where Tier 2 is used, EPA has provided for MSW combustion units to determine total CO_2 emissions from the amount of steam produced, boiler design, and a default CO_2 emission factor. EPA believes that this is more appropriate than determining site-specific factors during annual testing. Where Tier 4 is used, CO_2 emissions are determined using a CO_2 concentration monitor and a stack gas volumetric flow rate monitor. EPA does not believe that it is appropriate to estimate stack flow based on steam production in Tier 4, and does not believe it is appropriate to use an O_2 monitor for MSW combustion, since it is not a fuel listed in Table 1 in Section 3.3.5 of Appendix F to Part 75. Biogenic emissions for the MSW combustion unit are then calculated by multiplying the total CO_2 emissions for the year, determined using Tier 2 or 4, by the fraction of biogenic emissions, determined using the ASTM methods.

Commenter Name: Stephen E. Woock
Commenter Affiliation: Weyerhaeuser Company
Document Control Number: EPA-HQ-OAR-2008-0508-0451.1
Comment Excerpt Number: 18

Comment: Weyerhaeuser does not agree with the provisions requiring direct measurement of fuel use or the requirements to fuel test to calculate GHG emissions. Direct measurement of fuel usage, fuel carbon content and fuel heat content is an unnecessary activity, which can not be justified by any purported improvement in accuracy and would impose significant unnecessary costs. Instead, as allowed under most, if not all other GHG reporting systems, we propose that the activity data and emissions factor approach described in Tier 1 be allowed as an approach to calculate the GHG emissions from all stationary combustion sources. Emission factors are already conservative by design and will ensure the integrity of the reported emissions. Fuel purchase records, and facility or vendor provided default values for carbon and heat content can provide the level of accuracy necessary. Therefore, EPA should allow the use of accepted industry and vendor provided emission factors rather than mandating that the final consumer of the fuel undertake these new and costly analyses - which EPA should note, will generate it's own new and sizable carbon footprint as nationwide a very large new activity of sampling, shipping and testing samples comes on-line. There is no technical basis that would suggest that a facility level fuel test is more accurate than one done by the fuel vendor. The preferred approach would be to follow the conventions established by the Canadian and European Union's programs and allow either national average fuel-specific emission factors, those factors published by the IPCC, or site specific factors determined (through experience) to be even more appropriate for the specific example under evaluation. Direct measurement, as required by Tier 2 and 3 in the proposal, should be optional. Most regulated facilities have internal control procedures to determine which method is the most consistent and accurate for its operations given its fuels and fuel systems and multiple data analysis and reporting requirements.

Response: See the Preamble, Section II. L., on General Monitoring Requirements for the overall rationale for methodologies required under this rule, and the response to comment EPA-HQ-OAR-2008-0508-0909.1 for the rationale for methodologies required under Subpart C.

EPA has significantly expanded the use of Tier 1 and Tier 2 Calculation Methodologies. Units of any size combusting only pipeline quality natural gas and/or distillate oil may now use Tier 2, and most units combusting biogenic fuels may use Tier 1. The mandatory fuel sampling and analysis requirements for Tiers 2 and 3 have been considerably revised. The final rule requires that natural gas be sampled semiannually. For fuel oil and coal, a representative sampling is required for each fuel lot, i.e., for each shipment or delivery. For other liquid fuels and biogas, quarterly sampling is required. For other solid fuels, excluding municipal solid waste, weekly composite sampling with monthly analysis is required. For other gaseous fuels, the daily sampling requirement has been retained, but only for facilities with existing equipment in place that is capable of providing the data. Otherwise, weekly sampling is required. The final rule also clarifies that fuel sampling and analysis data provided by the supplier may be used in the emission calculations, and that fuel billing meters may be used to quantify fuel consumption.

Commenter Name: Kathleen M. Sgamma
Commenter Affiliation: Independent Petroleum Association of Mountain States (IPAMS)
Document Control Number: EPA-HQ-OAR-2008-0508-0521.1
Comment Excerpt Number: 17

Comment: IPAMS members prefer the use of fuel-based CH_4 and N_2O emission factors, which is consistent with aggregation of combustion sources using common meters.

Response: EPA appreciates the supportive feedback, and has maintained these specifications in the final rule.

Commenter Name: Michael W. Stroben
Commenter Affiliation: Duke Energy Corporation
Document Control Number: EPA-HQ-OAR-2008-0508-0407.1
Comment Excerpt Number: 16

Comment: EPA proposes to require monthly sampling of the carbon content of propane for Tier 2 and Tier 3 reporting methodologies. Propane is a very homogeneous fuel. The monthly sampling of the carbon content of propane is not going to provide materially different estimates of emissions that would result from applying a default emission factor. Duke Energy therefore recommends that facilities be allowed to use the default HHV and CO_2, CH_4, and N_2O emission factors for Tier 2 and Tier 3 reporting. If a facility is currently sampling propane for other purposes it could be allowed to use that information if it chose to do so, but this rule should not create a new requirement that facilities begin propane sampling.

Response: EPA has provided a default emission factor (kg CO_2/mmBtu) and HHV (mmBtu/gallon) in Table C-1 for propane. EPA expects that most units combusting propane will have maximum rated heat input capacities less than 250 mmBtu/hr, and will thus be allowed to use Tier 1 or Tier 2. Tier 1 does not require any fuel sampling or analysis. Tier 2 will only be required if the owner or operator of the unit already performs sampling and analysis for HHV, or receives the result of such analysis from the fuel supplier, at the minimum frequency. If a unit larger than 250 mmBtu/hr combusts propane, Tier 3 will be required, and fuel sampling and analysis for carbon content will be required.

EPA agrees with the commenter that for a relatively homogeneous fuel such as propane, monthly sampling is not necessary. For liquid fuels other than fuel oil, quarterly sampling is required in the final rule. However, regardless of the sampling frequency, the owner or operator must use the results of all available valid fuel analyses in the emissions calculations. The final rule also clarifies that fuel sampling and analysis data provided by the supplier may be used in the emission calculations.

Commenter Name: Michael Bradley
Commenter Affiliation: The Clean Energy Group (CEG)
Document Control Number: EPA-HQ-OAR-2008-0508-0479.1
Comment Excerpt Number: 15

Comment: The Clean Energy Group suggests including thermal energy in the inventory as well to calculate greenhouse gas intensity for combined heat and power (CHP) facilities. The Clean Energy Group requests that EPA allow CHP facilities to utilize the emission calculation protocol used by EPA's Climate Leaders program to apportion greenhouse gas emissions from thermal energy production in order to more accurately account for greenhouse gas emissions from such facilities.

Response: See the Preamble, Section II. D., and separate comment response document volumes for the responses on the selection of source categories to report and on the relationship of this rule to other programs.

In response to the comment, EPA does not believe that any additional language is needed to address the issue of greenhouse gas emissions calculation methods for combined heat and power facilities. While EPA recognizes the benefits associated with thermal energy production and its effect on GHG emissions, we believe that the Calculation Methodologies discussed in detail in §98.33 of the final rule provide accurate results to appropriately account for emissions data from general stationary combustion sources required to report GHG emissions.

Commenter Name: Thomas Siegrist
Commenter Affiliation: Koch Nitrogen Company LLC
Document Control Number: EPA-HQ-OAR-2008-0508-0351.1
Comment Excerpt Number: 15

Comment: The Proposed Rule would also require that process gas, which presumably would include purge gas from the ammonia process synthesis loop at the KNC ammonia production plants, be sampled and analyzed daily to determine the carbon content and molecular weight of the gas when used as a fuel (proposed §98.34(d)(3)). Synthesis loop purge gas composition is stable over time, and it provides a very small percentage of the overall fuel value consumed in the ammonia production facility. Whereas daily sampling and analyses of this stream would not significantly improve the quality of resulting emissions estimates, and would impose an unwarranted cost and operational burden, the Proposed Rule should be revised to reflect a required frequency of sampling and analyses of ammonia production purge gas, when used as a fuel for stationary combustion, of once per quarter.

Response: See the Preamble, Section II. L., on General Monitoring Requirements for the overall rationale for methodologies required under this rule, and the response to comment EPA-HQ-OAR-2008-0508-0909.1 for the rationale for methodologies required under Subpart C.

EPA has revised the sampling frequency requirement for gaseous fuels other than natural gas or biogas in Tier 3 from daily to weekly for facilities where equipment for daily sampling is not in place. EPA also has limited the mandatory use of Tier 3 to determine emissions from fuels for which no default values are provided to fuels that make up at least ten percent of the average annual heat input for a unit with maximum rated heat input capacity greater than 250 mmBtu/hr. Otherwise, emissions from the alternative fuels need not be reported unless CEMS are used.

Commenter Name: Laurie Burt
Commenter Affiliation: Massachusetts Department of Environmental Protection
Document Control Number: EPA-HQ-OAR-2008-0508-0453.1
Comment Excerpt Number: 14

Comment: Under Section V C of the Preamble, General Stationary Fuel Combustion Sources, Subsection 3d: Selection of Proposed Monitoring Methods: CH_4 and N_2O Emissions From All Fuel Combustion, EPA proposes to use default emission factors and annual heat input values to estimate CH_4 and N_2O emissions. Massachusetts suggests that EPA perform studies to improve these AP-42 emissions factors, which currently have a very low rating.

Response: EPA believes the CH_4 and N_2O emission factors provided in Subpart C are appropriate for use in this mandatory reporting rule. EPA has reviewed the values, and finds that they are consistent with Climate Leaders. Values brought in from IPCC were converted in the same manner as the Climate Leaders factors. EPA is using mostly IPCC values because we are aware that the AP-42 non-CO_2 factors haven't been reviewed in-depth recently.

Commenter Name: Thomas Siegrist
Commenter Affiliation: Koch Nitrogen Company LLC
Document Control Number: EPA-HQ-OAR-2008-0508-0351.1
Comment Excerpt Number: 14

Comment: The Proposed Rule would require facilities under Tier 2 to conduct monthly sampling and analysis of incoming natural gas fuel for higher heating value ("HHV") and would require facilities under Tier 3 to conduct monthly sampling and analyses for fuel carbon content and molecular weight. Both of these proposed calculation methods are costly and unnecessary. Ample historical data are available across industries that characterize HHV, carbon content, and molecular weight for common fuels such as pipeline-quality natural gas. Default values for these parameters could reliably be used to estimate combustion-related emissions with minimal reduction in overall emissions data quality. Use of default values is allowed under several accepted GHG reporting protocols, including those of the WRI/WBCSD and TCR. EPA should look to these established programs and eliminate the proposed requirement to sample and analyze for these parameters in common fuels, such as pipeline-quality natural gas. If EPA believes it necessary to require site-specific data, the reporting entity should be allowed to use data generated by the fuel supplier, rather than imposing an additional sampling and analytical burden on individual manufacturing sites.
Response: See the Preamble, Section II. L., for the response on the general monitoring approach. See the Preamble and separate comment response document volume for the response on the relationship of this rule to other programs.

The commenter should note that EPA has revised the rule to allow the use of Tier 2 to calculate emissions from a unit of any size in which pipeline quality natural gas and/or distillate oil are the only fossil fuels combusted. EPA agrees with the commenter that for a homogeneous fuel such as pipeline natural gas, monthly sampling is not necessary. The rule has been revised to require that natural gas be sampled semiannually. The final rule also clarifies that fuel sampling and analysis data provided by the supplier may be used in the emission calculations.

Commenter Name: Michael Bradley
Commenter Affiliation: The Clean Energy Group (CEG)
Document Control Number: EPA-HQ-OAR-2008-0508-0479.1
Comment Excerpt Number: 13

Comment: The Clean Energy Group understands that EPA is proposing that the electric utility industry continue to report CO_2 emissions on a quarterly basis to the Clean Air Markets Division (CAMD) and then sum the emissions at the end of the year and quantify CH_4 and nitrous oxide (N_2O) emissions. However, in some cases, total heat input values from oil and natural gas are recorded at the hourly level, but are not summed up separately on an annual basis. The Clean Energy Group requests that EPA provide methodologies to report CH_4 and N_2O for multiple fuel units on Acid Rain units.

Response: EPA acknowledges the concerns of commenters, and has added language to clarify the methodology for reporting CH_4 and N_2O for multiple fuel units under the Acid Rain Program. Please refer to §98.33(c) for detailed instructions.

Commenter Name: Thomas Siegrist
Commenter Affiliation: Koch Nitrogen Company LLC
Document Control Number: EPA-HQ-OAR-2008-0508-0351.1
Comment Excerpt Number: 12

Comment: KNC agrees with EPA's decision to allow the use of default emission factors to estimate CH_4 and N_2O emissions from fuel combustion given the low levels of these emissions and the high relative degree of accuracy of the emission factor method. The Proposed Rule would allow the use of default emission factors, in combination with annual heat input values, to estimate methane ("CH_4") and N_2O emissions from fuel combustion. Considering the relatively low combustion-related emission levels of CH_4 and N_2O, compared to those of CO_2, neither stack testing nor CEMs would provide a cost-effective alternative that would significantly improve upon the accuracy of a GHG emission inventory. KNC recommends that EPA retain the use of default emission factors for estimating combustion-related CH_4 and N_2O emissions in the final rule.
Response: EPA appreciates the supportive feedback, and has maintained these specifications in the final rule.

Commenter Name: Steven D. Meyers
Commenter Affiliation: General Electric Company (GE)
Document Control Number: EPA-HQ-OAR-2008-0508-0532.1
Comment Excerpt Number: 18

Comment: Section 98.33 of the proposed regulations provides a four-tiered GHG emissions calculation methodology for fuel combustion sources. These calculation methodologies range from use of default fuel specific heating value and CO_2 emission factors (Tier 1) to use of CEMS on large coal-fired units that are already equipped with CEMS (Tier 4). While GE understands the benefits of CEMS for those sources already employing CEMS; however, additional opportunities for error and data inconsistency are potentially introduced by Tier 2 and Tier 3 requirements. GE currently uses Tier 1 exclusively in calculating GHG emissions from its fuel combustion sources all over the world. In fact, GE is using factors that combine the fuel heating and emissions factors into a single factor. GHG emission can be simply calculated by multiplying the fuel volume, weight or mass times the appropriate factor. This has also allowed GE to preprogram these factors into our web-based data collection tool so that our sites do not need to calculate GHG emissions. In addition, GE's fuel combustion GHG emissions are calculated in a consistent manner throughout the US and the rest of the world so that meaningful comparisons can be made between sources and facilities. GE's GHG inventory also allows sites to combine all of their fuel combustion sources that fire the same fuel and apply the factor only once, greatly simplifying the data collection and emissions calculation processes because the sites must only collect the total quantity of each type of fuel used on site and enter this data into the web-based tool. Everything else is done for the site electronically. The proposed Mandatory Program provides three non-CEMS calculation methodologies. In Tier 1, the reporting site would have to select a default high heat value and CO_2 emission factor from a table and plug these values with the quantity of fuel consumed into the provided equation. In Tier 2, the reporting site would have to measure the actual high heat value of the fuel or obtain this information on a periodic basis from the fuel supplier, select a default CO_2 emission factor from a table and plug these values with the quantity of fuel consumed into the provided equation. Finally, in Tier 3, the site would have to periodically measure the fuel carbon content (molecular weight for gaseous fuels) and plug this information with the fuel use into an equation that assumes that all of the carbon is converted to CO_2. In each case the level of effort and complexity increases. Also, the opportunity for data error increases. GE understands that the accuracy of reporting theoretically increases as one moves from Tier 1 to Tier 2 to Tier 3. However, in Tier 1, EPA could program the default heat content and emission factors into its electronic tool so that the reporting facility only has to collect information on the quantity of fuel consumed and enter this data into the electronic tool. The reporting facility would only have to certify the quantity of fuel consumed. This would make the data quality assurance much easier, both for the reporting facility and for EPA. No mistakes could be made in the data calculations since the electronic reporting tool would do them all. When one moves to Tier 2, the site now has to obtain actual fuel heat content values on a periodic basis either by measuring and analyzing the fuel heat content or obtaining this information from the fuel supplier. This may introduce fuel sampling and analysis errors. Also the laboratory may not report the fuel heat content data accurately. Finally the site needs to enter another piece of data into the electronic tool, which could introduce data entry errors. GE presumes that the calculations could still be preprogrammed into the electronic reporting tool so that the sites would not have to do all of the calculations. This method is theoretically more accurate than Tier 1. However, the additional error opportunities that result from Tier 2 may cancel out any increase in theoretical accuracy. The move to Tier 3 requires the site to obtain actual fuel carbon content (molecular weight for gaseous fuels) data. This would force the reporting site to do fuel sampling and analysis since this data may not be reported by the fuel supplier (coal suppliers may report this data but oil and gas suppliers may not). This would introduce fuel sampling, analysis and reporting errors as discussed above for Tier 2. GE also presumes that the calculations could still be preprogrammed into the electronic reporting tool so that the sites would not have to do all of the calculations. Again this method is theoretically more accurate than Tier 1, however the additional error opportunities may cancel out any increase in theoretical accuracy. GE has learned that GHG reporting errors increase as the complexity of reporting increases. We have endeavored to make our process as simple as possible. We are concerned about the increase in complexity that is represented by Tiers 2 and 3. In addition, the three tiers will introduce variability as various reporting facilities select their calculation methodology. It is possible that three different reporting facilities with three identical units using the same source of natural gas may report three different GHG emission numbers because they have selected different calculation methodologies. GE recommends that EPA select a Tier 1 methodology for most standard fuels such as natural gas, distillate oil, propane, LPG, etc. that tend to have a more uniform composition to promote simplicity, accuracy and consistency in reporting. GE understands the need to go to Tiers 2 and 3 in cases where fuel variability may be more significant.

Response: See the Preamble, Section II. L., for the response on the general monitoring approach.

EPA did not choose to adopt a simplified calculation method approach (e.g., using default emission factors) for all units because the data would be less accurate than under the selected option and would not make use of site-specific data that many facilities already have available and refined calculation approaches that many facilities are already using.

However, EPA has significantly expanded the use of Tier 1 and Tier 2 Calculation Methodologies. Units of any size combusting only pipeline quality natural gas and/or distillate oil may now use Tier 2, and most units combusting biogenic fuels may use Tier 1. Furthermore, the mandatory fuel sampling and analysis requirements for Tiers 2 and 3 have been considerably revised. The final rule requires that natural gas be sampled semiannually. For fuel oil and coal, a representative sampling is required for each fuel lot, i.e., for each shipment or delivery. For other liquid fuels and biogas, quarterly sampling is required. For other solid fuels, excluding municipal solid waste, weekly composite sampling with monthly analysis is required. For other gaseous fuels, the daily sampling requirement has been retained, but only for facilities with existing equipment in place that is capable of providing the data. Otherwise, weekly sampling is required. The final rule clarifies that fuel sampling and analysis data provided by the supplier may be used in the emission calculations.

Please see Section V. of the Preamble on "Collection, Management, and Dissemination of GHG Emissions Data" for additional information on how EPA plans to approach electronic reporting and software tools.

Commenter Name: Rechelle Holloway
Commenter Affiliation: Tyson Foods, Inc.
Document Control Number: EPA-HQ-OAR-2008-0508-0379.1
Comment Excerpt Number: 10

Comment: Tyson agrees that EPA should allow the fuel supplier to provide fuel heating values for both Tier 1 and Tier 2 calculation methodologies. For EPA to require individual facilities to have tested either internally or externally is redundant to what fuel supply companies routinely assess and provide to their customers.

Response: The final rule clarifies that fuel sampling and analysis data provided by the supplier may be used in the emission calculations for both Tier 2 and Tier 3, while Tier 1 calculations use default heating values and emission factors.

Commenter Name: Traylor Champion
Commenter Affiliation: Georgia-Pacific, LLC (GP)
Document Control Number: EPA-HQ-OAR-2008-0508-0380.1
Comment Excerpt Number: 19

Comment: There is no need for Tier 4 Methodology. Under the proposed rule, a unit rated greater than 250 MMBtu burning solid fossil fuel that already has a CEMS installed for any pollutant would need to install a CEMS to determine CO_2 emissions and install a flow monitor system to enable the specified Tier 4 calculations. For almost all solid fossil fuels, there has been a large amount of data collected over many years on the HHV and CO_2 emissions associated with those fuels. Facilities that use solid fossil fuels track the amount of fuel purchased very closely since it is, in most cases, a significant part of the overall energy cost. Therefore, requiring a CEMS and flow meter for these units would be an unnecessarily burdensome and expensive new requirement that would not significantly improve the accuracy of CO_2 measurement over fuel-use based calculations.

Response: See the Preamble, Section II. L., for the response on the general monitoring approach.

The Tier 4 requirement described by the commenter is limited to larger solid fossil fuel units with an existing pollutant CEMS or volumetric flow rate monitor. EPA is requiring the use of CEMS due to the complexity of monitoring solid fuel consumption and the heterogeneous nature of the solid fuels, which reduces the accuracy of calculation methodologies. Many of these fossil fuel-fired units with a pollutant CEMS have an existing diluent monitor (O_2 or CO_2) that can be used to determine CO_2 emissions (General Stationary Combustion Technical Support Document, EPA-HQ-OAR-2008-0508-0004).

Commenter Name: Doug MacTaggart
Commenter Affiliation: C-Lock Technology, Inc.
Document Control Number: EPA-HQ-OAR-2008-0508-0502.1
Comment Excerpt Number: 10

Comment: We have developed an uncertainty analysis for CEMS emissions data that has been reviewed by several leading consultants in CEMS emissions measurements and statistical analysis. The uncertainty analysis C-Lock has developed calculates the uncertainty of a reference value compared with an instrument measurement and determines the uncertainty associated with the difference between the two values. Our uncertainty analysis includes the following data: (1) Measurement values obtained from both the CEMS and relative accuracy test audit (RATA) equipment during the RATA tests. Also, the number of accepted/passed RATA tests performed since 1997. (2) Measurement values from both CEMS instruments and reference instruments for high, low, and zero levels during daily calibrations. (3) Average hourly values measured by CEMS. (4) Cumulative number of concentration standard bottles used for daily calibrations since the last RATA test. (5) The number of RATA tests performed. The automated uncertainty analysis is built into our software to calculate the uncertainty for any unit in the Part 75 database. The overall finding is that mass flow rate of CO_2 (a combination of CO_2 flow rate and concentration) typically indicates errors with a magnitude of 4 - 5%. Note that no "absolute" measurements exist, therefore, no measurement method can be absolutely accurate in a scientific sense. Because there are no absolute measures with which to compare CEMS data, only repeated measurements of the same component using independent methods can approximate the latent value. Also note that our uncertainty analysis does not account for differences between the CEMS field measurements, reference values, and the "absolute measurement" because it is impossible to determine the "absolute measurement." This principle has been affirmed on several occasions by our consultants who have significant experience with CEMS systems. We have found that uncertainty estimates provided through this type of analysis are definitely biased low. Therefore, the "absolute" uncertainty is likely greater than the 4-5% uncertainty specified by our calculations. A summary of CEMS bias studies drawing from publications by several organizations shows that the potential for measurement bias found by multiple authors ranges between 3-30%, depending on the equipment used, equipment maintenance, and set-up [See DCN: EPA-HQ-OAR-2008-0508-0502.1 for Appendix references 3-9]. C-Lock engineers have also performed extensive data mining of the Part 75 database. As a result, we have observed many indicators of CEMS data discrepancies. For example, one key variable analyzed is CO_2 emission intensity (CO_2 generated per gross unit power produced) and its variability over time. In well-operated and maintained units, the CO_2 emission intensity does not change significantly over time. Our investigations indicate that changes in CO_2 emission intensity can be attributable to one or more of the following factors: (1) Changes in plant heat rate over time including seasonal changes. (2) Changes in coal quality over time. (3) Changes in steam usage over time (i.e., steam is used for some other purpose than to generate electricity). (4) Change in the measurement systems. Although plants in the US that use steam for purposes other than generating electricity exist, they are few and far between. Therefore, in most cases item #3 can be eliminated as a contributor to changes in emission intensity. C-Lock has also analyzed the reported heat rate data in the Part 75 database. We recognize that the reported heat rate in this database is calculated based on reported CO_2 emissions data, unit power output data, and standardized F-factors. Therefore, this heat rate data most likely will not align with actual heat rate data calculated by plant operators using methods independent of the F-factor approach. However, the Part 75 database [1] heat rate data, particularly changes in heat rate over time, do provide an indicator of the validity of the CEMS CO_2 data. Our analysis of the Part 75 database indicates many irregular changes in CO_2 intensity and heat rate. Some examples are shown in the series of plots in Attachment 1. Our analysis of the data from the 422 single-units with single stacks that burn coal and emitted more than one million metric tons of CO_2 in 2007 indicates the following for the 2007 year: (1) Of the 422 single-units with single stacks, 212 (50%) of those units indicate greater variations in CO_2 intensity than 10%. [Footnote: This is after accounting for constant plant load conditions (greater than 90% load) and calculating 14 day rolling averages. The difference reported is the difference between the minimum and maximum 14-day averaged value for the 2007 year] (2) Out of the 422 units, 56 units (13%) were determined to have 14-day CO_2 intensity variations of greater than 20%. [see footnote above] (3) Most of the changes in intensity are not likely to represent real changes in emission intensity because the intensity swings in many cases aren't logical. Relative to heat rate, the data in the Part 75 database indicate many irregular changes as well. Our analysis of the data from the same units, show the following: (1) Of the 422 single-units with single stacks, 199 (47%) of those units indicate greater changes in heat rate than 1,000 BTU/KWh. [see footnote above] (2) Of the 422 single-units with single stacks, 49 (12%) of those units indicate greater changes in heat rate than 2,000 BTU/KWh. [see footnote above] (3) Because the changes are so large, most of the changes in intensity are not likely to represent real changes in heat rate. We have also made other observations based on data from the Part 75 database: (1) In most cases, the variations in "apparent" intensity can not be correlated with major plant outages and the variations often appear to be random with no logical explanation (i.e., the CO_2 intensity degrades over time, an outage occurs, then the CO_2 intensity is recovered). (2) Differences of 6% in CO_2 intensity and heat rate based on CEMS measurement data have been observed for facilities with identical units burning coal from the same fuel source. If this was an actual emissions intensity change, this would represent approximately a 600 BTU difference among identical units; this is a highly unlikely occurrence. [See DCN: EPA-HQ-OAR-2008-0508-0502.1 for table illustrating 2007 yearly average heat rates associated with average emission intensities] (3) Data from older, less efficient units operating from the same coal source are often reporting a 5-10% better heat rate and CO_2 intensity than units that are newer and have been reported as performing more efficiently. [See DCN: EPA-HQ-OAR-2008-0508-0502.1 for figures illustrating filtered intensity of two different units] Unit 1 began operation in 1978, while Unit 2 began in 1994. These units have the same emission controls, coal source, and are both dry-bottom units. However, the older unit shows a more efficient performance throughout 2007. [See DCN: EPA-HQ-OAR-2008-0508-0502.1 for table summarizing the trends of the two units according to average yearly emissions intensity in 2007. Unit #1 at 30 years of age contains a 2007 yearly average intensity of 0.86 $mtCO_2$/MWh; Unit #2 at 14 years of age contains a 0.93 $mtCO_2$/MWh yearly average intesnity. Commenter points out a 7% difference between the two units.]

Response: See the Preamble, Section II. L., for the response on the general monitoring approach.

See the response to comment EPA-HQ-OAR-2008-0508-0502.1 excerpt 9 for an explanation of EPA's analysis of the use of the mass balance approach for emissions from solid fuels such as coal.

The Tier 4 CEMS requirement is limited to larger solid fossil fuel units with an existing pollutant CEMS or volumetric flow rate monitor. EPA is requiring the use of CEMS due to the complexity of monitoring solid fuel consumption and the heterogeneous nature of the solid fuels. Many of these fossil fuel-fired units with a pollutant CEMS have an existing diluent monitor (O_2 or CO_2) that can be used to determine CO_2 emissions (General Stationary Combustion Technical Support Document, EPA-HQ-OAR-2008-0508-0004).

Commenter Name: John L. Wittenborn et al.
Commenter Affiliation: Steel Manufacturers Association (SMA) and Specialty Steel Industry of North America (SSINA)
Document Control Number: EPA-HQ-OAR-2008-0508-0518.1
Comment Excerpt Number: 9

Comment: SMA/SSINA support the use of default emission factors for estimating methane and nitrous oxide emissions from combustion. Given that these emissions are insignificant at steel mills, we agree that the additional costs and burdens of using CEMS or developing site-specific emissions factors is not warranted.

Response: EPA appreciates the supportive feedback and has maintained these specifications in the final rule.

Commenter Name: Gary Moore
Commenter Affiliation: Pensacola Plant of Ascend Performance Materials LLC
Document Control Number: EPA-HQ-OAR-2008-0508-0366.1
Comment Excerpt Number: 9

Comment: Allowances should be made to subtract fugitive emissions of natural gas, calculated according to the procedures in Subpart W, from the total amount combusted on a single site.

Response: Subpart C allows for combustion emission calculations based only on the fuel combusted. Subpart C has been revised to allow units of any size combusting only pipeline quality natural gas to use Tier 2 to calculate emissions. Tier 2 requires facilities to determine fuel use from company records. EPA intends that this provision will allow a reporting facility to accurately determine the quantity of fuel combusted using the most appropriate methods for that facility. EPA points out that it is not finalizing Subpart W at this time.

Commenter Name: Doug MacTaggart
Commenter Affiliation: C-Lock Technology, Inc.
Document Control Number: EPA-HQ-OAR-2008-0508-0502.1
Comment Excerpt Number: 9

Comment: C-Lock promotes and supports that the intent of the EPA reporting rule to maintain scientific credibility and transparency in reporting emissions data. However, based on the uncertainty observed in Continuous Emission Monitoring Systems (CEMS) emissions data contained in the EPA's Part 75 database, it can be reasonably concluded that CEMS can be relatively uncertain and not sensitive enough to reliably quantify changes in CO_2 emissions that result from feasible, but relatively small (1% - 3%) improvements in unit heat rate. Heat rate improvements of 1 - 3% are simply "lost in the noise" of the larger uncertainty associated with CEMS data. C-Lock has developed an uncertainty analysis for the Part 75 CEMS CO_2 emissions data that has been reviewed by several leading consultants in CEMS emissions data and statistical analysis. While analyzing the uncertainty of numerous units in the EPA's Part 75 emissions database, it was found that, in general, mass flow rate of CO_2 (a combination of CO_2 flow rate and concentration) typically has an uncertainty of at least 4 - 5%, and is likely higher after considering the unknown variables that were not available for our analysis. This uncertainty is simply too large to accurately and reliably quantify efficiency improvements that will lead to reduced CO_2 emission rates. We have also noted numerous inconsistencies in the historical CEMS CO_2 emission data, these inconsistencies indicate that reported data may be inaccurate for many US coal-fired units, by as much as 20%. Inaccuracies in reported data will make it difficult to establish credible baselines, which will, in turn, impact future reduction goals. Measurement error will also have significant effects on the integrity of any trading platform. The current requirements and procedures employed in the US to measure and report CO_2 have evolved primarily from the rules that govern the measurement and reporting of SO_2 and NO_x emissions. C-Lock does not endorse applying this "cookie-cutter" approach to CO_2 emissions monitoring. Managing CO_2 emissions is different than managing SO_2 and NO_x emissions because CO_2 is a process emission. For example, when monitoring SO_2 emissions, the sulfur content of coal is 25 - 100 times less than the carbon content and much more variable. Also, flue gas desulfurization equipment ("scrubbers") can be used to remove SO_2 from the flue gas, therefore making mass-balance calculations more difficult and less certain. Similar issues exist for the management of NO_x emissions. NO_x is formed from the oxidation of nitrogen in the boiler as a result of the combustion process, and scrubbers are can also be used to remove NO_2 from the exit gas stream. Because of these issues, CEMS is probably the most accurate, smallest "headache," and most cost-effective method for determining NO_x and SO_2 emissions, but the same is not necessarily true for CO_2. The most important point is that there are alternate, independent, and relatively low-cost methodologies to compute CO_2 emissions from a coal-fired unit that can be used to compare with CEMS data. Two accepted, and relatively inexpensive methods that can be used to calculate CO_2 emissions are a carbon mass balance calculation based on coal quality and quantity data and CO_2 emissions calculated using plant heat rate and statistically valid emissions factors for coal. In addition, comparing independent process indicators, such as comparing coal feed rates and induced-draft fan flows with emissions output, can indicate potential for error in a CEMS CO_2 monitoring system. Process variables can also be used to reliably show that actions to reduce CO_2 emissions translate into a quantifiable benefit. Many plants already use real-time, on-line monitoring systems that perform these measurements on a continuous basis for performance reasons. Combining these techniques could significantly reduce the variations and associated uncertainty of any single measurement technique.

Response: See the Preamble for the response on the general monitoring approach.

The Tier 4 CEMS requirement is limited to larger solid fossil fuel units with an existing pollutant CEMS or volumetric flow rate monitor. EPA is requiring the use of CEMS due to the complexity of monitoring solid fuel consumption and the heterogeneous nature of the solid fuels. Many of these fossil fuel-fired units with a pollutant CEMS have an existing diluent monitor (O_2 or CO_2) that can be used to determine CO_2 emissions (General Stationary Combustion Technical Support Document, EPA-HQ-OAR-2008-0508-0004).

Commenter Name: Douglas P. Scott
Commenter Affiliation: The Climate Registry
Document Control Number: EPA-HQ-OAR-2008-0508-0567.2
Comment Excerpt Number: 8

Comment: The Registry recommends requiring the use of emissions factors based on combustion technology to quantify CH_4 and N_2O emissions from stationary combustion. EPA currently prescribes the use of default emission factors for CH_4 and N_2O based on fuel type. The Registry has worked with a variety of stakeholders on this issue and based on those discussions believes it is more accurate to quantify these emissions using emission factors based on combustion technology.

Response: The use of fuel-specific emission factors is in accordance with methods used in other programs. The approach provides data of sufficient accuracy for the purposes of this rule, given that CH_4 and N_2O emissions from stationary combustion are much less than CO_2 emissions.

Commenter Name: Steven M. Maruszewski
Commenter Affiliation: Pennsylvania State University (Penn State)
Document Control Number: EPA-HQ-OAR-2008-0508-0409.1
Comment Excerpt Number: 8

Comment: Penn State agrees that the approach to allow facilities to aggregate emissions from small units is the appropriate approach. It allows EPA to obtain the data required but with a reasonable amount of effort on the reporter's part.

Response: EPA appreciates this comment, and believes that the final rule includes further clarification and flexibility regarding aggregation and common pipe provisions that will reduce the burden on sources.

Commenter Name: Kerry Kelly
Commenter Affiliation: Waste Management (WM)
Document Control Number: EPA-HQ-OAR-2008-0508-0376.1
Comment Excerpt Number: 7

Comment: If EPA decides to use thresholds to determine the applicability of the various calculation methodologies, then the MRR should include an alternative threshold for use of Tier 4 for MWCs. EPA should base the threshold on non-biogenic CO_2 emissions equivalent to a 250 MMbtulhr natural gas fired combustion source. Using the emission factors and assumptions in the calculations above, we propose the following: "(5) Tier 4 Calculation Methodology: ...(ii) Shall be used if: ..., or if the unit combusts municipal solid waste, and if non-biogenic CO_2 emissions are greater than 13,255 kilograms per hour calculated using maximum permitted heat input in MMBtu per hour, Table C-2 default emission factor and the non-biogenic fraction from ASTM D 6866-06a results."

Response: EPA appreciates your comment but has kept the 250 ton MSW/day size determination. Both the 250 mmBtu/hr and 250 tons MSW/day are size determinations for considering large sources in other EPA programs (e.g., 40 CFR 60 Subpart Ea and Eb for Municipal Solid Waste Combustors). These size determinations were not considered to be directly comparable, but rather to reflect consistency with other EPA programs.

Commenter Name: See Table 4
Commenter Affiliation:
Document Control Number: EPA-HQ-OAR-2008-0508-0455.1
Comment Excerpt Number: 7

Comment: Under Subpart C of the Proposal, the Agency proposes to subject large solid fuel-fired combustion sources with existing Continuous Emission Monitoring Systems ("CEMS") equipment to Tier Four monitoring requirements and emissions calculation methods, which are the most stringent of the proposed monitoring requirements. In the Preamble, the Agency justifies this stringency based on "the complexity of monitoring solid fuel consumption and the heterogeneous nature of solid fuels." The Class of '85 disagrees with the assertion that the nature of solid fuels justifies such stringent monitoring requirements and emissions calculation methods for CO_2. Large stationary combustion units fired with solid fuels are subject to stringent monitoring requirements and emissions calculation methods under the Acid Rain Program. The Group agrees that stringent monitoring and emissions calculations are justified under the Acid Rain Program, as the primary pollutant to track is sulfur dioxide ("SO_2"). The Group does not believe, however, that the same justification applies with regard to CO_2 emissions. The variability of sulfur in coal is significant, but variation in the carbon content of coal is much less. Because of the homogenous carbon content of coal, the Class of '85 believes that a solid fuel-fired combustion source should be allowed to calculate CO_2 emissions based on carbon content measurements and the amount of coal burned, so long as a facility can certify its coal quantity measurements. The Class of '85 urges EPA to consider this rationale when evaluating the stringency of its monitoring requirements and emissions calculation methods for large solid fuel-fired combustion sources.

Response: EPA believes that while variability in the carbon content may be of concern, the more significant issue is the ability to accurately determine the quantity of solid fossil fuel consumption. EPA notes that the commenter also adds the following caveat to the suggested technique of calculating CO_2 emissions based on carbon content measurements and the amount of coal burned, "so long as a facility can certify its coal quantity measurements." EPA refers the commenter to the report DCN: EPA-HQ-OAR-2008-0508-0696.2 submitted to the docket by Clean Air Engineering (CAE), which states the use of a mass balance technique for determining CO_2 mass emissions can result in significant underestimation of emissions (between 18 – 77 percent lower than CO_2 mass emissions determined using CEMS). While a mass balance approach may be useful for providing a "ball park" check on the reasonability of the data collected, EPA believes that there is ample evidence to show that properly operated and maintained CEM systems provide the best available real-time data. EPA has not seen any evidence that mass balance data are of high enough quality to be considered an equivalent to CEMS data. Recent information presented at forums such as Air and Waste Management Association (AWMA) conferences suggests that a 20 percent error in the measurement of solid fuel consumption is not uncommon, without taking into account any additional calibration drift that may occur in the belt scales and gravimetric feeders in-between calibration checks.

Commenter Name: Steven M. Maruszewski
Commenter Affiliation: Pennsylvania State University (Penn State)
Document Control Number: EPA-HQ-OAR-2008-0508-0409.1
Comment Excerpt Number: 7

Comment: EPA has proposed a 4-tiered system for calculating emissions from stationary sources. Emissions from smaller sources/units can be calculated from measured fuel use and default heat values. This avoids the cost burden of adding continuous emissions monitoring systems (CEMS) for smaller units. Large emitters involved in ARP already have these systems. Penn State agrees with this approach.

Response: EPA appreciates your support and thanks you for your comment. See the Preamble, Section II. L., for the response on the general monitoring approach.

Commenter Name: Doug MacTaggart
Commenter Affiliation: C-Lock Technology, Inc.
Document Control Number: EPA-HQ-OAR-2008-0508-0502.1
Comment Excerpt Number: 7

Comment: Under the proposed rule, electricity generation units (EGU) falling under the EPA Acid Rain Program (i.e., large coal-fired plants) would be required to report CO_2 emissions using their existing Continuous Emission Monitoring System (CEMS). For general stationary fuel combustion sources not including EGUs, the proposed rule stipulates a four-tier approach for determining the methodology to be used to quantify CO_2 emissions. Tier 4 would apply to large facilities that combust solid fossil fuel (i.e., coal) and require reporters to use CEMS if it is already installed at their facility. Tier 3 would apply mainly to combustion of more homogeneous liquid and gaseous fossil fuels and would require periodic determination of the carbon content of the fuel combined with direct measurement of the amount of fuel combusted. EPA states that they evaluated calculation methods for coal combustion used in other emissions reporting programs. EPA found that these methods would introduce significant uncertainty into the reported CO_2 emissions estimates based on the heterogeneous nature of coal, the relative infrequency of coal sampling required by the methods (often only monthly), their lack of inclusion of heat input capacity of stationary combustion equipment, and the use of company records to estimate fuel consumption. C-Lock has found that relying solely on CEMS for quantification of power plant emissions can result in significant uncertainty and that the key to reducing this uncertainty is inclusion of additional data feeds and calculation methods into the quantification process [See DCN: EPA-HQ-OAR-2008-0508-0502.1 Appendix A for details]. In addition, C-Lock has found that the issues with coal sampling identified by EPA can be rectified by more rigorous sampling and analysis methodologies. In particular, ASTM International standards specifying much more frequent sampling of coal [See DCN: EPA-HQ-OAR-2008-0508-0502.1 for references for ASTM standards D7430, D6883, D6609, D2234/D2234M, and D2013] are commonly used to control business transactions related to buying and selling of coal. Thus, C-Lock advocates providing coal-fired EGUs and other large stationary fuel combustion facilities with the opportunity to use emission quantification methods based on consumed fuel as long as the more rigorous ASTM procedures are followed. This will result in increased accuracy of the reported emissions and a more accurate baseline for future programs.

Response: The commenter did not explain what is meant by "more rigorous ASTM procedures" for quantifying solid fossil fuel consumption, or the basis for believing that these procedures are capable of providing CO_2 emissions estimates equivalent to direct measurement of CO_2 emissions with a CEMS. The commenter does refer to a number of ASTM coal sampling techniques, which could be used to measure the carbon content of the fuel, but are not suitable for quantifying solid fossil fuel consumption.

Commenter Name: David A. Buff
Commenter Affiliation: Florida Sugar Industry (FSI)
Document Control Number: EPA-HQ-OAR-2008-0508-0500.1
Comment Excerpt Number: 11

Comment: The FSI agrees with EPA that requiring periodic stack testing to derive site-specific emission factors for CH_4 and N_2O is too costly and thus not justified. Stack testing for this purpose is not likely to produce any meaningful improvement in the quality of the emissions data. As EPA acknowledged in the Preamble to the proposed rule, the CH_4 and N_2O emissions from stationary combustion sources are relatively low compared to the CO_2 emissions. The proposed approach, i.e., using fuel-specific default emission factors to calculate CH_4 and N_2O emissions, is in accordance with methods used in other programs and provides data of sufficient accuracy. Moreover, EPA also should recognize that many sources may have CH_4 stack test data available, because of requirements in their Title V or construction permits to measure VOC emissions. Where a facility has CH_4 stack test data available, it makes sense to require such data to be used.

Response: EPA acknowledges the concerns of the commenters. For the purpose of the rule, which is data collection for policy development, we would prefer consistent use of default CH_4 and N_2O emission factors. In this case, we provide the values we would like reporters to use in Table C-2, and for verification purposes, would prefer consistent use of these factors. Additional factors may be brought into future programs, but for this rulemaking, given the very small comparative amounts of CH_4 and N_2O emitted compared to CO_2, we have chosen to use the defaults provided in Table C-2. The commenter should note that EPA has revised the final rule to exclude CH_4 and N_2O emissions from fuels for which the rule does not provide emission factors, and has deleted the provision allowing the owner or operator of a facility to develop site-specific emission factors for such fuels. EPA believes that this change will reduce the reporting burden on facilities.

Commenter Name: Doug MacTaggart
Commenter Affiliation: C-Lock Technology, Inc.
Document Control Number: EPA-HQ-OAR-2008-0508-0502.1
Comment Excerpt Number: 11

Comment: C-Lock advocates using CEMS data, coal analysis data, and plant heat rate, along with other parameters, simultaneously and in near-real-time. If comparison of these data reveals inconsistencies, the operator has the responsibility to identify the measurement problem and to resolve the differences quickly. By relating CO_2 emissions to multiple plant processes and data feeds, the performance of a unit can be closely monitored and small, incremental improvements can be documented in multiple transparent, accurate, and verifiable ways, thus increasing market credibility and value. [See DCN: EPA-HQ-OAR-2008-0508-0502.1 for figure illustrating how additional data feeds can be used to check for potential errors in plant process and monitoring data] Coal Data Coal is a valuable commodity, and samples are taken and analyzed from nearly 100% of coal shipments. Analysis of SO_2 emission potential is reported in each weigh-bill, and checked prior to unloading. ASTM standards [10-21] are used daily around the world to control business transactions related to coal buying and selling. Standardization by adherence to accepted ASTM procedures is the key to improved value and understanding between buyer and seller. We advocate following ASTM procedures whenever possible. Fossil power plants are required by United States law to report coal analysis and mass consumption to the Federal Energy Regulatory Commission (FERC). Under these requirements, every power plant must report basic coal analysis and mass burned. FERC requires proximate analysis of extrinsic properties which includes moisture, volatile matter, fixed carbon, ash (by difference), sulfur, and BTU/lb determination. In order to determine carbon dioxide from combustion, ultimate analysis of intrinsic properties, for carbon, hydrogen, nitrogen, oxygen (by difference) is required. These properties can be obtained from the same sample, but each requires additional laboratory expense. C-Lock is also working in the European Union (EU) to quantify GHG emissions and reductions under the EU Emissions Trading System (EU ETS). In the EU, CEMS data are not typically used to quantify CO_2 emissions. The EU methodology utilizes coal quantity and quality as a basis for CO_2 emission determinations. The relevant European directive instructs that if CEMS data are used to determine emissions, it must be clearly demonstrated that results provide a more accurate representation of annual emissions than using coal data and the measurements must still be verified with calculations based on fuel [See references 22-23 in Appendix of DCN: EPA-HQ-OAR-2008-0508-0502.1]. There is a justifiable need to compare accuracy of CEMS and Carbon Mass Balance (CMB) calculations over time because they are completely independent methods to estimate CO_2 emissions. By comparing the two, errors in either method can be identified and problems can be solved immediately. We advocate stringent quality assurance and quality control requirements as laid out by the EPA and ASTM for both CEMS and CMB because the uncertainty of the calculated emission rates is directly related to the quality of the data. Heat Rate Data The Electric Power Research Institute (EPRI) stated in March 2009 that, "the only cost-effective, near-term option for reducing net CO_2 emissions from coal-fired power plants is to reduce the amount of coal used. Reducing plant heat rate is an effective means of reducing coal consumption" [See reference 24 in Appendix of DCN: EPA-HQ-OAR-2008-0508-0502.1]. Unit heat rate is presently widely measured and used to determine the efficiency of a power plant as it depends on the unit design, fuel, and capacity factor. With sufficient unit data, CO_2 emissions can be computed accurately using unit heat rate measurements and statistical valid emissions factors for the coal being burned. The quality of heat rate data used to calculate CO_2 emissions will have a significant impact of their accuracy. Multiple techniques for measurement of unit heat rate are available, and studies have been conducted by the Lehigh University Energy Research Center (ERC) to compare them. For example, one study [See reference 25 in Appendix of DCN: EPA-HQ-OAR-2008-0508-0502.1] examines heat rates computed using the Input/Output, Output/Loss, Boiler/Turbine-Cycle Efficiency (BTCE), and F-factor approaches. During this study, the ERC found that because the accuracy of the F-factor method is directly dependent on the accuracy of flue gas flow rate measurements and errors in CEMS flow rate ranged between 5 and 20 percent at many installations, the F-factor approach is the least accurate. The study also found the Input/Output method to be more accurate with typical unit measurement uncertainty in the 1.5 to 3 percent range (it is important to note that in a coal-fired unit the error is largely a random error). The Output/Loss and BTCE methods are significantly more accurate than the Input/Output Method, with typical measurement uncertainties in the 0.75 to 1.5 percent range (the errors in measured turbine cycle heat rate are typically systematic or bias errors). Both the Output/ Loss and BTCE methods can be used fairly easily to obtain highly accurate results on heat rate differences. The ERC study also found it is possible, with minimal effort, to implement two or more of the methods at once, and the simultaneous use of several performance measurement methods greatly increases confidence in the results. Process Variables Comparing independent process data, such as comparing trends in coal feed rates and induced-draft fan flows with trends in CEMS emissions, mass flow rate and intensity can indicate potential for error in a CEMS CO_2 monitoring system. Unlike SO_2 and NO_x emissions, with CO_2 emissions, there are typically many process data points that should trend well with CEMS data that should be considered to help validate emissions data. Process variables can also be used to accurately quantify incremental reductions related to actions that result in 1 - 3% efficiency improvements. With the larger uncertainty associated with total unit or facility emissions rates, 1 - 3% efficiency improvements are simply "lost in the noise" of the larger emissions uncertainty. This is further compounded when multiple units are connected to a single stack. The incentive to increase plant efficiencies becomes minimal when the ability to link actions to incentives is lost by using only total emissions rates. Efficiency improvements are often measurable using process specific data related to the improvement. Using specific process data, determination of increased efficiency related to a specific improvement can be made. Once the increase in efficiency is determined, the incremental decrease in CO_2 emissions associated with the improvement can be determined. This approach has been successfully used before in the carbon markets, and has been approved under the Clean Development Mechanism (CDM) of the Kyoto protocol [See references 26-27 in

Appendix of DCN: EPA-HQ-OAR-2008-0508-0502.1]. However, the entire process needs to be documented in a straight-forward, transparent way. The approach for quantifying increased efficiency of specific components (and associated emissions reductions) is not new and there are many specific ASME standards defining the best accepted practice on how to determine efficiencies of various components within a power plant [See reference 28-35 in Appendix of DCN: EPA-HQ-OAR-2008-0508-0502.1].

Response: EPA refers the commenter to the report DCN: EPA-HQ-OAR-2008-0508-0696.2 submitted to the docket by Clean Air Engineering (CAE), which states the use of a mass balance technique for determining CO_2 mass emissions can result in significant underestimation of emissions (between 18 – 77 percent lower than CO_2 mass emissions determined using CEMS). While a mass balance approach may be useful for providing a "ball park" check on the reasonability of the data collected, EPA believes that there is ample evidence to show that properly operated and maintained CEM systems provide the best available real-time data. EPA has not seen any evidence that mass balance data are of high enough quality to be considered an equivalent to CEMS data. Recent information presented at forums such as Air and Waste Management Association (AWMA) conferences suggests that a 20 percent error in the measurement of solid fuel consumption is not uncommon, without taking into account any additional calibration drift that may occur in the belt scales and gravimetric feeders in-between calibration checks.

Commenter Name: Edward N. Saccoccia
Commenter Affiliation: Praxair Inc.
Document Control Number: EPA-HQ-OAR-2008-0508-0977.1
Comment Excerpt Number: 5

Comment: EPA should not require the use of the Tier 4 method where alternative fuel consumption data is available. Tier 1, 2, and 3 offer viable alternatives for many combustion sources that will yield comparable, and in many cases, more accurate emission estimates. Allow optional use of the Tier 4 method where, at the source's discretion. This may be a suitable calculation method where a source uses multiple fuels and/or non-commercial fuels or where existing CEMS systems include CO_2 measurement or can be modified at lower cost than alternative fuel consumption and/or characterization devices/practices. In any case, let the regulated source determine which method is most cost effective for their particular situation.

Response: See the Preamble, Section II. L., for the response on the general monitoring approach.

EPA has considerably revised §98.33(b), describing which tier a reporter is to use. Tier 2 is now available to units combusting only pipeline natural gas and/or distillate fuel oil, and most units combusting only biogenic fuels may now use Tier 1. EPA has revised §98.33(b)(4)(ii) of the final rule to clarify that all six criteria specified in subparagraphs (A) through (F) must be met before Tier 4 is required. The Tier 4 CEMS requirement is limited to larger solid fossil fuel units with an existing pollutant CEMS or volumetric flow rate monitor. EPA is requiring the use of CEMS due to the complexity of monitoring solid fuel consumption and the heterogeneous nature of the solid fuels.

Commenter Name: Jeffrey L. Clark
Commenter Affiliation: Environmental Coordinator, Teck Alaska Incorporated
Document Control Number: EPA-HQ-OAR-2008-0508-0142
Comment Excerpt Number: 5

Comment: The definitions of Tier 1, 2, 3, and 4 are nebulous and will result in confusion over which calculation methods should apply. Two of the Tiers regulate sources less than 250 mmBtus. Perhaps there should be a lower level cutoff exempting the use of the more complex calculations and analysis of fuels for smaller facilities. Are all GHG sources rated in mmBtus? If not, some of the EPA's calculation will not work. If one has a MSW incinerator with no co-generated steam, the Tier 1 MSW GHG calculation will yield 0.

Response: EPA acknowledges the commenter's concerns, and has substantially revised §98.33(b) in the final rule, relaxing tier and calculation method applicability. EPA believes that the revised language makes it clear which tier calculation method(s) a reporter may use. The revised rule also adds considerable flexibility, allowing more reporters to use the lower tiers. EPA has allowed units that combust MSW but do not produce steam to calculate their emissions using Tier 1 methods, which do not use the quantity of steam generated.

Commenter Name: Keith A. Nagel
Commenter Affiliation: ArcelorMittal USA and Severstal North America
Document Control Number: EPA-HQ-OAR-2008-0508-0496.1
Comment Excerpt Number: 10

Comment: Section 98.33(c)(4) requires owners/operators to develop site-specific CH_4 and N_2O emissions factors based on source testing where default factors are not provided for particular fuel types. Since the Proposed Rule does not contain default factors for either blast furnace gas or coke oven gas, this provision would obligate steel plants to generate site-specific emissions factors for these fuels based on testing. Such testing would be very difficult (if not impossible) because many of our combustion sources simultaneously fire multiple fuels at constantly changing levels or are flares which are impossible to test. While the burden of developing site-specific factors is high, the CH_4 and N_2O emissions at issue are orders of magnitude less significant than related CO_2 emissions at these sources. Since the vast majority of process gas combustion at steel mills occurs at very high temperatures, very little N_2O is created. With respect to methane, "CH_4 emissions from stationary combustion are primarily a function of the CH_4 content of the fuel and combustion efficiency." See Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 – 2007 at p. 3 - 7. While comparatively more difficult to combust (due to its lower Btu value), blast furnace gas contains almost no CH_4 to begin with. See The Making, Shaping and Treating of Steel, 11th ed. (1999) at p. 347 (indicating that blast furnace gas only contains "approximately 0.2% CH_4"). Coke oven gas contains significantly more CH_4 but is combusted very efficiently due to its much higher Btu content. Since both the presence of CH_4 and inefficient combustion are necessary, neither coke oven gas combustion nor blast furnace gas combustion emits meaningful amounts of methane. Given the significant challenges associated with the development of site-specific factors in this context and the very small relative amount of CH_4 and/or N_2O emissions that results from the combustion of blast furnace gas and coke oven gas, we request that EPA delete the requirement to report CH_4 and N_2O emissions from sources primarily combusting blast furnace gas and/or coke oven gas. Alternately, if EPA declines to delete this requirement, we request that EPA defer such reporting pending the development of industry-wide default factors. ArcelorMittal and Severstal stand ready to work with EPA to develop such factors if the final rule is so amended.

Response: EPA acknowledges the concerns of the commenters. EPA has revised the rule so that CH_4 and N_2O emission calculations are only required for those fuels listed in Table C-2 of Subpart C. Default factors for coke oven and blast furnace gases have been added to Table C-2.

Commenter Name: John H. Skinner
Commenter Affiliation: Solid Waste Association of North America (SWANA)
Document Control Number: EPA-HQ-OAR-2008-0508-0659.1
Comment Excerpt Number: 10

Comment: The Tier 3 methodology requires monthly direct measurements of fuel carbon content, which would require extremely large samples in order to be representative for MSW and is not technically feasible for WTE operations. As the rule is currently written WTE facilities without monitors are only given the option of Tier 3 for 2010, but Tier 2 is more appropriate for WTE facilities. We recommend that the Tier 2 method be used by all WTE operations.

Response: EPA has revised the rule so that those units that must upgrade their existing CEMS to meet Tier 4 requirements may use either Tier 2 or 3 in 2010, if all the required monitors have not been installed and certified by January 1, 2010.

Commenter Name: Michael DiMauro
Commenter Affiliation: Massachusetts Municipal Wholesale Electric Company (MMWEC)
Document Control Number: EPA-HQ-OAR-2008-0508-0580
Comment Excerpt Number: 10

Comment: The Tiered Monitoring Scheme presented in the Proposed Rule (Section 98.33) is overly complicated, does not represent a real progression in measurement accuracy, and contains overly burdensome fuel sampling requirements for units with a heat input > 250 MMBtu/hr. a) The Four Tier Approach – Shortcomings/Misconceptions i. O2 Monitoring using a Flow/CO_2 Monitor CEMS vs. a Fuel Metering Monitoring System: In the Tiered Monitoring approach for stationary sources presented in Section 98.33, the Part 75 Flow Monitor/CO_2 CEMS measurement method is assigned the highest accuracy Tier (IV). However, as far as I am aware, no justification for this assumption is provided in the rule Preamble, and several factors suggest that CO_2 emissions derived from Fuel Meter measurements are of comparable accuracy to those determined from Part 75 Flow/CO_2 CEMS. In particular: 1. CEMS Flow Monitors are essentially calibrated to match Reference Method flow measurements determined in accordance with procedures detailed 40 CFR 60 Appendix A Method 1 and 2. These Reference Method flow measurements are normally performed using standard Pitot tubes, which are subject to inaccuracies if there are any cyclonics in the stack flow [Part 75 does provide an option to perform flow testing using 3-D probes, which can eliminate much of this inaccuracy, however there is no requirement to use such 3-D Probes]. 2. The Part 75 RATA accuracy threshold for flow monitors and for CO_2 monitors are each + / -10%, so that the resulting CO_2 emissions measurement error using this flow/CO_2 CEMS method is potentially significantly higher than 10%. 3. Part 75 RATA flow testing is only performed at 2 or 3 loads, and ongoing QA for flow monitors is limited. 4. In contrast, most oil and gas fuel meters used at EGU sites have accuracies of better than 1% across the meter scale range, and if fuel meter measurements begin to drift, such excursions will typically be noticed quickly as the overall operation of the combustion unit will be adversely affected. 5. It might also be noted that under the original 40 CFR 75 rule, oil fired combustion units were not permitted to monitor CO_2 emissions using fuel meters, however based on evidence provided to EPA showing that CO_2 emissions determined by fuel metering closely tracked emissions determined using Flow/CO_2 monitors, along with other supporting information, the 40 CFR 75 rule was revised to allow oil fired units to monitor CO_2 using fuel meters. In general then, there is no reason to expect CO_2 determined from fuel metering to be any less accurate than that determined from Flow/CO_2 CEMS. ii. CO_2 Monitoring using a Flow/O2 Monitor CEMS: Inclusion of the Part 75 Flow/O2 Monitor CEMS in the highest accuracy Tier (IV) is particularly inappropriate and inconsistent with the Tiered accuracy concept, as this CEMS system relies on the very default CO_2 emission factors that are the basis for relegating sources in the Tier II category to a lower accuracy status – see Formulas F- 14a and F 14b in 40 CFR 75 Appendix F. iii. Fuel Usage from Company Records vs. Direct Fuel Metering: when determining fuel usage on a long term (annual) basis, there is no reason to expect data values derived from meter measurements to be inherently more accurate than values extracted from company records, particularly if the company records are based on fuel delivery billings or billing invoices provided by the supplier. For the same reasons that billing meters are assumed accurate (see Part 75 Appendix D), fuel delivery data can be presumed equally accurate. And over the course of a year, any inaccuracies introduced in the process of converting fuel delivery data to fuel consumption values (e.g. accounting for changes in Oil Tank levels) should be relatively small, and even these small sources of error can be largely eliminated in most cases (i.e. by measuring Tank oil levels at the beginning and end of the year). Overall, then, there does not appear to be any compelling evidence to support the notion that the four Tiers (I to IV) established in the Proposed Rule represent a progressive trend toward increased accuracy. Rather, at least for long term emissions tracking, they may simply represent four different approaches that differ in methodology more than inherent quality. The idea of allowing different monitoring approaches is strongly supported, however the idea of classifying them in a progressive hierarchy does not seem justified.

Response: EPA does not agree with the commenter's assessment. Tier 4 is required only for the combustion of solid fossil fuel and municipal solid waste, whereas Tier 3 requires the use of calibrated fuel flow meters to quantify the consumption of liquid and gaseous fuels. The fuel flow meters that the commenter believes will provide more accurate data than a CEMS, cannot be used for solid fuels. So the basic premise of the commenter's argument does not apply in this context. The only direct comparison that can be made between the accuracy of Tiers 3 and 4 is for solid fossil fuel combustion. Tier 3 requires the use of "company records" to quantify solid fossil fuel usage. As discussed in the preamble to the proposed rule, EPA has serious concerns about the accuracy of coal belt scales and other equipment used to measure coal feed rates. Therefore, the Agency maintains its position that the Tier 4 method is more accurate than Tier 3, when the two Tiers are compared on an equivalent basis.

Commenter Name: Keith A. Nagel
Commenter Affiliation: ArcelorMittal USA and Severstal North America
Document Control Number: EPA-HQ-OAR-2008-0508-0496.1
Comment Excerpt Number: 9

Comment: The other major impediment to application of Tier 1 and Tier 2 methods at many steel plant combustion sources is the Proposed Rule's limitation of these methods to units "with a maximum rated heat input capacity of 250 mmBtu/hr or less." See §§98.33(b)(1) and (3). That threshold is arbitrary in that it has no direct link to GHG emissions. For example, a 249 mmBtu/hr boiler combusting coal would have a much more significant carbon footprint than a 300 mmBtu/hr boiler burning blast furnace gas and/or coke oven gas. Thus, as currently written, this requirement would disproportionately impact sources that intentionally promote the reuse of waste gases in lieu of additional fossil fuel consumption. To avoid that unintended impact, we request that EPA either delete the 250 mmBtu/hr threshold requirement entirely for units combusting process gases (which would strongly encourage energy conservation) or link the use of Tier 1 and Tier 2 methodology to a specific CO_2e threshold.

Response: EPA has significantly expanded the use of Tier 2 calculation methods for units that combust natural gas and distillate oil, in view of the homogeneous nature and low variability in the characteristics of these fuels. Furthermore, Tier 1 is available to units of all sizes combusting biomass fuels from Table C-1. However, the Tier 3 methodology is still required for large 250 mmBtu/hr units that combust other fuels, including blast furnace gas and coke oven gas.

For gaseous fuels other than natural gas and biogas, due to variability, the daily sampling requirement has been retained, but only for facilities with existing equipment in place that is capable of providing the data. Otherwise, weekly sampling is required.

The 250 mmBtu/hr size determinations is used for considering large sources in other EPA programs, and EPA believes that the use of tiers based on this determination is appropriate.

Commenter Name: Alexander D. Menotti
Commenter Affiliation: Kelley Drye & Warren et. al LLP on behalf of the Steel Manufacturers Association (SMA) and Specialty Steel Industry of North America (SSINA)
Document Control Number: EPA-HQ-OAR-2008-0508-0656.1
Comment Excerpt Number: 9

Comment: SMA/SSINA support the use of default emission factors for estimating methane and nitrous oxide emissions from combustion. Given that these emissions are insignificant at steel mills, we agree that the additional costs and burdens of using CEMS or developing site-specific emissions factors is not warranted.

Response: EPA appreciates the supportive feedback, and has maintained these specifications in the final rule.

Commenter Name: John H. Skinner
Commenter Affiliation: Solid Waste Association of North America (SWANA)
Document Control Number: EPA-HQ-OAR-2008-0508-0659.1
Comment Excerpt Number: 8

Comment: SWANA believes the threshold applied to WTE facilities for Tier 4 reporting must be consistent with the reporting threshold applied to other stationary fuel combustion sources. Tier 2 calculations may be used for stationary combustion units where the maximum rated heat input capacity is 250 mmBtu/hr or less; however, a different threshold of 250 tons / day is applied to units that combust MSW. Based on a nominal heat content of 5,000 Btu / lb, the 250 tons / day threshold is equivalent to 104 mmBtu/hr, less than half the standard applied to other stationary combustion units. Conversely, a 250 mmBtu/hr threshold applied to nominal MSW would translate into a mass rate threshold of approximately 600 tons / day. According to EPA's most recent national GHG inventory (Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2007, April 2009) WTE facilities emit very small amounts of GHG relative to other electricity producing sources. Of total CO_2e emissions from the Combustion Source sector in EPA's proposed reporting rule, waste-to-energy facilities account for only 0.55 percent. Unless a facility is already equipped with both a stack gas volumetric flow rate monitor and a CO_2 CEM, Tier 4 reporting should not be required. Instead facilities should be allowed to use the Tier 2 reporting method. Installation of these additional reporting methods will not extensively improve the accuracy of the data reported, in a manner in which to justify the substantial additional costs. SWANA requests consistency amongst all the stationary fuel combustion sources and recommends that WTE be allowed to use the Tier 2 method to calculate their emissions regardless of tons per day received.

Response: EPA appreciates your comment but has kept the 250 ton MSW/day size determination. Both the 250 mmBtu/hr and 250 tons MSW/day are size determinations for considering large sources in other EPA programs (40 CFR 60 Subpart Ea and Eb for Municipal Solid Waste Combustors.). These size determinations were not considered to be directly comparable, but rather to reflect consistency with other EPA programs. However, EPA believes that it is appropriate to require the use of CEMS on the largest MSW combustion sources and any smaller MSW combustion source which already has CO_2 concentration monitors and stack gas volumetric flow rate monitors in place.

Commenter Name: Kyle Pitsor
Commenter Affiliation: National Electrical Manufacturers Association (NEMA) Magnet Wire Section
Document Control Number: EPA-HQ-OAR-2008-0508-0622.1
Comment Excerpt Number: 8

Comment: The NEMA Magnet Wire EHS Committee is supportive of EPA's thinking as to allowing calculation of aggregate CO_2 equivalents from oil-fired and/or gas-fired units combusting the same fuel.

Response: EPA appreciates this comment, and believes that the final rule includes further clarification and flexibility regarding aggregation and common pipe provisions that will reduce the burden on sources.

Commenter Name: Kyle Pitsor
Commenter Affiliation: National Electrical Manufacturers Association (NEMA) Magnet Wire Section
Document Control Number: EPA-HQ-OAR-2008-0508-0622.1
Comment Excerpt Number: 7

Comment: The NEMA Magnet Wire EHS Committee requests greater clarification as to the EPA's thinking about "reducing volume of waste by removing combustible matter" as it relates to EPA's expectations for reporting CO_2 equivalents. Specific to the magnet wire industry as related to stationary fuel combustion sources, magnet wire ovens generally serve two noteworthy functions: production of useful heat and thermal treatment of solvent-laden gases. The NEMA Magnet Wire EHS Committee believes that it would be reasonable to exclude CO_2 equivalents resulting from combustion of solvent-laden gases as a function of controlling volatile organic compound (VOC) air emissions, and thus limit calculations in such cases to CO_2 from supplemental burner gas alone. This will focus the calculations, and the additional CO_2 from combusting solvent-laden gases should be light relative to supplemental burner fuel. If, however, EPA insists that CO_2 equivalents from combusting solvent-laden gases must be included, then the reporting entity should be allowed to calculate CO_2 emissions based on engineering calculations of estimated chemical stoichiometry of typical solvents destroyed.

Response: EPA acknowledges the concerns of the commenter and has revised §98.33 to deal with certain unconventional combustion processes and types of fuel. In the Preamble, EPA has explained that "devices such as thermal oxidizers and pollution control devices . . . would report only the GHG emissions from the firing of supplemental fossil fuels." EPA believes that these provisions satisfy the intent of Part 98, to collect accurate and consistent GHG emissions data that can be used to inform future decisions.

Commenter Name: Kyle Pitsor
Commenter Affiliation: National Electrical Manufacturers Association (NEMA) Magnet Wire Section
Document Control Number: EPA-HQ-OAR-2008-0508-0622.1
Comment Excerpt Number: 6

Comment: Carbon dioxide (CO_2) equivalent emissions from industrial boilers and process heaters combusting natural gas and/or common industrial fuels (i.e., #2 and #6 fuel oil) should be calculated using existing standard emission factors and/or fundamentals of chemical stoichiometry. Demanding analysis for carbon content is excessive when calculating emissions from burning natural gas and common industrial fuels in industrial boilers and process heaters, and there is certainly no cause for warranting continuous emissions monitoring systems (CEMS) for this exercise when considering industrial boilers and process heaters burning common industrial fuels.

Response: EPA has revised the rule to allow the use of Tier 2 methods (with default carbon contents per HHV) for calculating emissions from units of any size in which the only fossil fuels combusted are pipeline quality natural gas and/or distillate fuel oil. Furthermore, the mandatory fuel sampling and analysis requirements for Tiers 2 and 3 have been considerably revised. The final rule requires that natural gas be sampled semiannually. For fuel oil and coal, a representative sampling is required for each fuel lot, i.e., for each shipment or delivery.

The Tier 4 CEMS requirement is limited to larger solid fossil fuel units with an existing pollutant CEMS or volumetric flow rate monitor. EPA is requiring the use of CEMS due to the complexity of monitoring solid fuel consumption and the heterogeneous nature of the solid fuels. Many of these fossil fuel-fired units with a pollutant CEMS have an existing diluent monitor (O_2 or CO_2) that can be used to determine CO_2 emissions.

Commenter Name: Traylor Champion
Commenter Affiliation: Georgia-Pacific, LLC (GP)
Document Control Number: EPA-HQ-OAR-2008-0508-0380.1
Comment Excerpt Number: 18

Comment: The proposed tiered approach for calculating emissions from stationary combustion sources is complex and burdensome, and does not lead to better data. GP requests the use of Tier 1 for all emissions reporting. GP has experience in conducting GHG inventories according to reputable protocols such as WRI/WBCSD and ISO 14064.1. We satisfactorily use the method of activity data multiplied by default emission factors as used in these established protocols and standards as well as The Climate Registry's (TCR) General Reporting Protocol, which is analogous to EPA's proposed Tier 1 calculation methodology for general stationary combustion sources. All these protocols and standards are accurate and sufficient. GP believes that CO_2 continuous emissions monitoring systems (CEMS) should only be required for purposes of this greenhouse gas reporting rule where the CO_2 CEMS and stack gas volumetric flow rate monitors are already installed as required by an applicable Federal or State regulation or the unit's operating permit, similar to the proposed requirement under the Western Climate Initiative's, Final Draft Essential Requirements of Mandatory Reporting for the Western Climate Initiative. For all other cases, regardless of the fuel combusted or the size of the combustion units at a facility, emission calculations should be based on the use of activity data, default emission factors, and default HHVs (as applicable). This method is essentially EPA's proposed Tier 1 calculation methodology, which should apply to all incoming fuels, both fossil and biogenic, "across the fence" rather than at the unit level. Unit specific data provides no additional value in terms of facility emissions, yet add a significant and unnecessary reporting burden.

Response: See the Preamble, Section II. L., on General Monitoring Requirements for the overall rationale for methodologies required under this rule, and the response to comment EPA-HQ-OAR-2008-0508-0909.1 excerpt 4 and EPA-HQ-OAR-2008-0508-0580 excerpt 10 for the rationale for methodologies required under Subpart C.

The Tier 4 CEMS requirement is limited to larger solid fossil fuel and MSW units with an existing pollutant CEMS or volumetric flow rate monitor. EPA is requiring the use of CEMS due to the complexity of monitoring solid fuel consumption and the heterogeneous nature of the solid fuels. Many of these fossil fuel-fired units with a pollutant CEMS have an existing diluent monitor (O_2 or CO_2) that can be used to determine CO_2 emissions.

EPA has attempted to reduce the burden on reporters using the Tier 2 and Tier 3 methodologies. The mandatory fuel sampling and analysis requirements for Tiers 2 and 3 have been considerably revised. EPA agrees with the commenters that for a homogeneous fuel such as pipeline natural gas, monthly sampling is not necessary. For other fuels such as oil and coal, which are delivered in shipments or lots, requiring monthly sampling may be impractical; new fuel lots or deliveries may not be received on a monthly basis. Therefore, §98.34 has been revised to require that natural gas be sampled semiannually. For fuel oil and coal, a representative sampling is required for each fuel lot, i.e., for each shipment or delivery. For other liquid fuels and biogas, quarterly sampling is required. For other solid fuels, excluding municipal solid waste, weekly composite sampling with monthly analysis is required. For other gaseous fuels, the daily sampling requirement has been retained, but only for facilities with existing equipment in place that is capable of providing the data. Otherwise, weekly sampling is required. The final rule clarifies that fuel sampling and analysis data provided by the supplier may be used in the emission calculations, and that fuel billing meters may be used to quantify fuel consumption. To simplify the emission calculations in Tiers 2 and 3, averaging of HHV and carbon content data is permitted if these data are obtained at least at the minimum frequency specified in §98.34, but less frequently than monthly (see §98.33(a)(2)(ii)). If sampling is more frequent, the reporter must calculate a weighted average according to Equation C-2b. However, regardless of the sampling frequency, the owner or operator must use the results of all available valid fuel analyses in the emissions calculations.

EPA does not agree with the commenter's assertion that the amount of unit-level data and verification information to be reported is excessive, burdensome, or unnecessary. For this mandatory GHG emissions reporting rule, two main approaches to data verification were considered, i.e., EPA verification and third-party verification. EPA decided on the former approach. In view of this, additional, unit-level information is deemed necessary to provide assurance that the reported facility-wide GHG emissions data are both credible and accurate. However, EPA has dropped the cumulative 250 mmBtu/hr heat input capacity limit on the aggregation of units. Rather, the 250 mmBtu/hr restriction applies only to the individual units in the group. Therefore, for reporting purposes, individual units with maximum rated heat input capacities of 250 mmBtu/hr or less may be aggregated without limit into a single group, provided that the Tier 4 methodology is not required for any of the units, and all units in the group use the same tier for any common fuel(s) that they combust. Units with maximum rated heat inputs greater than 250 mmBtu/hr using Tiers 1, 2, and 3 must report as individual units, unless they burn the same type of fuel, and the fuel is provided by a common pipe or supply line; in that case, the owner or operator may opt to use the common pipe reporting provisions in §98.36(c)(3). Units using Tier 4 must report as individual units unless they share a monitored common stack or duct; in that case, the common stack or duct reporting provisions may be used.

Commenter Name: Duplicate of 0481.2
Commenter Affiliation: Duplicate of 0481.2
Document Control Number: EPA-HQ-OAR-2008-0508-0506.2
Comment Excerpt Number: 5

Comment: In the Preamble, EPA states that flares, not explicitly identified in another subpart, are to be reported under Subpart C. For most of the chemical industry that use flares, the carbon content of the waste gases will not be listed in either Table C-1 or C-2. Therefore, reporting of flare greenhouse gas emissions would be done under Tier III of Subpart C, under which flares would be treated the same as boilers or process heaters rather than as a unique source category. The Tier III procedure is not consistent with the flare estimation procedures described in Subpart Y for refinery flares, nor is it representative as drafted for these sources as explained below. INVISTA recommends that the emission reporting for flares that are subject to Subpart C follow a procedure that, to the extent applicable, follows the refinery flare methodology. When adopting the refinery flare methodology, it is important to note that there are two major differences between flares at chemical plants and those at refineries. First, for the non-refinery industry, the higher heating value (HHV) of the fuel is not an accurate indicator of the carbon content of the waste gas stream due to the high hydrogen content. Specifically, if a waste gas stream has hydrogen as a constituent at significant levels, the heating value of the waste gas stream will be high, but, the greenhouse gas emission rate will not increase. Facilities that have hydrogen content in their waste gas streams cannot accurately use any of the existing formulas in the proposed rule that are based on HHV. Second, the waste gas streams for chemical plants, among other facility types, have the potential to contain many complex hydrocarbons. Given the complexity of the waste gas streams, continuous monitoring of the carbon content may be widely variable and technically challenging, if not infeasible. A gas chromatograph-based (GC) monitor would have to be programmed to detect many potential components, lengthening the analysis time and leading to smaller concentrations, thus decreasing accuracy of the monitoring results. Given these monitor performance expectations, the GC will require more frequent maintenance and consequent loss of monitor uptime. These factors indicate that a continuous monitoring of carbon content is not a practical requirement for these waste gas streams. Finally, it is anticipated that the flare contributions to a facility's overall greenhouse gas emissions will be insignificant. Therefore, annual sampling of the waste gas streams is recommended and would be sufficiently representative of carbon content, based upon the existing refinery flare calculation procedures in Subpart Y, with modifications to address the differences between refinery and non-refinery flares, discussed above. To address the concerns discussed above and to modify the calculation procedures in Subpart Y, INVISTA recommends that EPA insert a new subparagraph (c) in section 98.33, between existing subparagraphs (b) and (c); existing subparagraph (c) and following subparagraphs would be changed accordingly. This inserted paragraph would specify the greenhouse gas emission calculations for non-refinery flares based on the refinery flare calculation procedure found in section 98.253(b). The recommended text would read as follows: (c) For flares, calculate GHG emissions according to the requirements in paragraphs (b)(1) and (2) of this section for combustion systems fired with process waste gases. (1) Calculate the CO_2 emissions according to the applicable requirements in paragraphs (c)(1)(i) through (iii) of this section. (i) Flow measurement. If you have a continuous flow monitor on the flare, you must use the measured flow rates when the monitor is operational, to calculate the flare gas flow. If you do not have a continuous waste gas flow monitor on the flare, or the flow monitor is down during a waste gas combustion period, you must use engineering calculations, company records, or similar estimates of volumetric flare gas flow. (ii) Carbon content. Complete annual carbon analysis of the combined waste gas stream being routed to the flare. Calculate the CO_2 emissions from the flare using Equation C-x. (iii) Startup, shutdown, malfunction. If you do not measure the higher heating value or carbon content of the flare gas at least daily, determine the quantity of gas discharged to the flare separately for periods of routine flare operation and for periods of start-up, shutdown, or malfunction, and calculate the CO_2 emissions as specified in paragraphs (c)(1)(iii)(A) and (B) of this section. (A) For periods of start-up, shutdown, or malfunction, use engineering calculations and process knowledge to estimate the carbon content of the flared gas for each start-up, shutdown, or malfunction event. (B) Calculate the CO_2 emissions using Equation C-x of this section. [See submittal DCN: EPA-HQ-OAR-2008-508-0506.2 for the equation and variables.]

Response: EPA has exempted flares from GHG emissions reporting under Subpart C, except where reporting flare emissions is required under another subpart of the rule.

Commenter Name: W. Walter Tyler
Commenter Affiliation: INVISTA S.a r.l. (INVISTA)
Document Control Number: EPA-HQ-OAR-2008-0508-0481.2
Comment Excerpt Number: 5

Comment: Clarify emission calculation for Waste Gases to Flares at non-Refinery facilities. In the Preamble, EPA states that flares, not explicitly identified in another subpart, are to be reported under Subpart C. For most of the chemical industry that use flares, the carbon content of the waste gases will not be listed in either Table C-1 or C-2. Therefore, reporting of flare greenhouse gas emissions would be done under Tier III of Subpart C, under which flares would be treated the same as boilers or process heaters rather than as a unique source category. The Tier III procedure is not consistent with the flare estimation procedures described in Subpart Y for refinery flares, nor is it representative as drafted for these sources as explained below. INVISTA recommends that the emission reporting for flares that are subject to Subpart C follow a procedure that, to the extent applicable, follows the refinery flare methodology. When adopting the refinery flare methodology, it is important to note that there are two major differences between flares at chemical plants and those at refineries. First, for the non-refinery industry, the higher heating value (HHV) of the fuel is not an accurate indicator of the carbon content of the waste gas stream due to the high hydrogen content. Specifically, if a waste gas stream has hydrogen as a constituent at significant levels, the heating value of the waste gas stream will be high, but, the greenhouse gas emission rate will not increase. Facilities that have hydrogen content in their waste gas streams cannot accurately use any of the existing formulas in the proposed rule that are based on HHV. Second, the waste gas streams for chemical plants, among other facility types, have the potential to contain many complex hydrocarbons. Given the complexity of the waste gas streams, continuous monitoring of the carbon content may be widely variable and technically challenging, if not infeasible. A gas chromatograph-based (GC) monitor would have to be programmed to detect many potential components, lengthening the analysis time and leading to smaller concentrations, thus decreasing accuracy of the monitoring results. Given these monitor performance expectations, the GC will require more frequent maintenance and consequent loss of monitor uptime. These factors indicate that a continuous monitoring of carbon content is not a practical requirement for these waste gas streams. Finally, it is anticipated that the flare contributions to a facility's overall greenhouse gas emissions will be insignificant. Therefore, annual sampling of the waste gas streams is recommended and would

be sufficiently representative of carbon content, based upon the existing refinery flare calculation procedures in Subpart Y, with modifications to address the differences between refinery and non-refinery flares, discussed above. To address the concerns discussed above and to modify the calculation procedures in Subpart Y, INVISTA recommends that EPA insert a new subparagraph (c) in section 98.33, between existing subparagraphs (b) and (c); existing subparagraph (c) and following subparagraphs would be changed accordingly. This inserted paragraph would specify the greenhouse gas emission calculations for non-refinery flares based on the refinery flare calculation procedure found in section 98.253(b). The recommended text would read as follows: (c) For flares, calculate GHG emissions according to the requirements in paragraphs (b)(1) and (2) of this section for combustion systems fired with process waste gases. (1) Calculate the CO_2 emissions according to the applicable requirements in paragraphs (c)(1)(i) through (iii) of this section. (i) Flow measurement. If you have a continuous flow monitor on the flare, you must use the measured flow rates when the monitor is operational, to calculate the flare gas flow. If you do not have a continuous waste gas flow monitor on the flare, or the flow monitor is down during a waste gas combustion period, you must use engineering calculations, company records, or similar estimates of volumetric flare gas flow. (ii) Carbon content. Complete annual carbon analysis of the combined waste gas stream being routed to the flare. Calculate the CO_2 emissions from the flare using Equation C-x. (iii) Startup, shutdown, malfunction. If you do not measure the higher heating value or carbon content of the flare gas at least daily, determine the quantity of gas discharged to the flare separately for periods of routine flare operation and for periods of start-up, shutdown, or malfunction, and calculate the CO_2 emissions as specified in paragraphs (c)(1)(iii)(A) and (B) of this section. (A) For periods of start-up, shutdown, or malfunction, use engineering calculations and process knowledge to estimate the carbon content of the flared gas for each start-up, shutdown, or malfunction event. (B) Calculate the CO_2 emissions using Equation C-x of this section [See DCN: EPA-HQ-OAR-2008-0508-0481.2 for equation calculating CO_2 emissions from flare gas].
Response: EPA has exempted flares from GHG emissions reporting under Subpart C, except where reporting flare emissions is required under another subpart of the rule.

Commenter Name: Duplicate of 0481.2
Commenter Affiliation: Duplicate of 0481.2
Document Control Number: EPA-HQ-OAR-2008-0508-0506.2
Comment Excerpt Number: 2

Comment: Like many other companies, INVISTA has taken steps to determine estimates of total GHG emissions through established industry standards and protocols that utilize fuel consumption data and recognized emission factors. For example, the Climate Registry (TCR), the WRI/WBCSD and ISO 14064.1 standards and protocols utilize well-recognized and well-established default emission factors for estimating GHG emissions that are comparable to the proposed methodology in Tier 1 of the Proposed Rule. This data has shown to be a reliable indicator, not only for tracking inventory and product manufacturing costs, but also in some instances for emissions estimates needed under other environmental regulatory programs, such as the Clean Air Act's Title V program. The Proposed Rule, however, specifies a 4-Tier reporting structure that is much more complex than other GHG reporting systems. The requirements in the Proposed Rule – including enhanced direct emissions monitoring, total carbon content analysis, and fuel-flow meters – demand significant additional investments at manufacturing sites with little gain in accuracy of emissions estimates over that which can be obtained by using current, accepted industry practice. In addition, the Tier 3 and 4 categories require an unspecified level of precision and accuracy to estimate and report GHG emissions based upon devices, measurements, or data that either do not exist currently at many facilities or have not been used historically for reporting or compliance purposes. For example, many facilities subject to this rule back-calculate fuel usage based on accepted industry standards and techniques such as inventory reconciliation, steam flow, or process knowledge which have been used for other reporting and accounting purposes. If EPA determines that this proposed Tiered approach is the preferred vehicle for reporting, then INVISTA recommends that EPA clarify that current industry standards and practice, such as inventory reconciliation, are within the meaning and intent of "company records" upon which many of the emission calculations in the Proposed Rule are based. However, simplifying the current scheme and basing it on recognized reporting methodologies, such as default emission factors, will alleviate much of the uncertainty in the Rule while sacrificing little if any of the accuracy EPA hopes to achieve in this reporting scheme. For these reasons, INVISTA recommends that Tier I methodology be adopted for all source categories.

Response: See the Preamble, Section II. L., on General Monitoring Requirements for the overall rationale for methodologies required under this rule, and the response to comment EPA-HQ-OAR-2008-0508-0909.1 excerpt 4 and EPA-HQ-OAR-2008-0508-0580 excerpt 10 for the rationale for methodologies required under Subpart C.

EPA has significantly expanded the use of Tier 1 and Tier 2 Calculation Methodologies. The 250 mmBtu/hr restriction on the use of Tier 2 has been lifted for units in which the only fossil fuels combusted are natural gas and/or distillate oil, in view of the homogeneous nature of these fuels. Most units combusting the biogenic fuels in Table C-1 may use Tier 1. However, the 250 mmBtu/hr unit size cutoff remains for units that combust other fuels. EPA has considerably revised the Tier 2 and Tier 3 fuel sampling requirements in an effort to reduce the burden on reporters. Furthermore, the final rule clarifies that fuel sampling and analysis data provided by the supplier may be used in the emission calculations, and that fuel billing meters may be used to quantify fuel consumption.

EPA has defined the term "company records" in §98.6 of the final rule. EPA believes that the revised definition provides appropriate guidance as to what records a facility may use to determine fuel consumption.

Commenter Name: Edward N. Saccoccia
Commenter Affiliation: Praxair Inc.
Document Control Number: EPA-HQ-OAR-2008-0508-0977.1
Comment Excerpt Number: 2

Comment: The proposed rule defines the applicability of the alternate calculation method "tiers" based on combustion unit size and availability of data, with a general trend to require more rigorous calculation methods (e.g. increasing from Tier 1 to Tiers 2, 3, and 4) for higher operating capacity units and facilities that currently employ certain process or emission measurements. Higher tiers often require a more costly, laborious measurement/calculation method that does not improve the accuracy or completeness of the emission estimate. In many instances, less rigorous calculation methods (e.g. "lower" Tiers) will yield comparable (or better) accuracy emission estimates, with higher reliability and at lower cost. There is an implied assumption that directly measured emissions will yield a better emission estimate. This presumption is not true, as evidenced by an acceptable level of (in)accuracy tolerance under CEMS certification/calibration procedures (> 5 - 7%) versus levels of fuel consumption metering employed for invoice billing (typically < 2%). EPA has previously recognized the concept of approving alternative monitoring approaches under the New Source Performance Standards (NSPS), 40 CFR Part 60, and the MACT regulations found at 40 CFR Part 63. This program has shown to be highly successful in providing an adequate balance between regulatory flexibility for the operating facilities and the need for rigorous process monitoring for compliance demonstration purposes. However, EPA has not included this allowance in the current proposed rule. EPA should allow more flexibility as it relates to the applicability to the alternate combustion emission calculation methods. In particular: 1. Allow use of the Tier 1 method for units of any size (currently restricted to units < 250 mmBTU/hr or less), particularly for standard fuels of commerce such as natural gas, LP gas and fuel oils, where billing-quality consumption data is accurate and readily available and the default HHV and CO_2 emission factors are well known constants (as noted in the Preamble for the proposed rule – natural gas carbon content is always within 1% of the default ratio). 2. Do not require the use of the Tier 4 method where alternative fuel consumption data is available. Allow optional use of the Tier 4 method where, at the source's discretion. This may be a suitable calculation method where a source uses multiple fuels and/or non-commercial fuels or where existing CEMS systems include CO_2 measurement or can be modified at lower cost than alternative fuel consumption and/or characterization devices/practices. In any case, let the regulated source determine which method is most cost effective for their particular situation. This option is available in California's GHG mandatory reporting program. 3. EPA should incorporate into the final rule a mechanism for authorizing alternative monitoring plan requests submitted on a facility by facility basis consistent with its current program under NSPS and MACT.

Response: See the Preamble, Section II. L., for the response on the general monitoring approach.

EPA did not choose to adopt a simplified calculation method approach (e.g., using default emission factors) for all units because the data would be less accurate than under the selected option and would not make use of site-specific data that many facilities already have available and refined calculation approaches that many facilities are already using. Methodologies that reflect the variability of fuels across units and facilities through sampling and measurement are more accurate than methodologies that do not account for this variability. The gains from measurement vary by fuel type (i.e., heterogeneity of carbon content and heat rate is lower in some fuels) and the final rule accounts for this difference by varying the requirements for units, with due consideration of burden and cost.

EPA has significantly expanded the use of Tier 1 and Tier 2 Calculation Methodologies. The 250 mmBtu/hr restriction on the use of Tier 2 has been lifted for units that combust only natural gas and/or distillate oil, in view of the homogeneous nature of these fuels. Units of any size combusting only biomass fuels listed in Table C-1 may use Tier 1 methods. However, the 250 mmBtu/hr unit size cutoff remains for units that combust other fuels.

The Tier 4 CEMS requirement is limited to larger solid fossil fuel units with an existing pollutant CEMS or volumetric flow rate monitor. EPA is requiring the use of CEMS due to the complexity of monitoring solid fuel consumption and the heterogeneous nature of the solid fuels.

Many of these fossil fuel-fired units with a pollutant CEMS have an existing diluent monitor (O_2 or CO_2) that can be used to determine CO_2 emissions.

Commenter Name: Ted Michaels
Commenter Affiliation: Energy Recovery Council (ERC)
Document Control Number: EPA-HQ-OAR-2008-0508-0544.1
Comment Excerpt Number: 1

Comment: All Municipal Waste Combustors Should be Allowed to use the Tier 2 Calculation Methodology for Reporting GHG Emissions under the Mandatory Reporting Rule (MRR) The MRR proposes to require all municipal waste combustors (MWC) with a maximum rated input capacity of greater than 250 tons per day of MSW to use the Tier 4 calculation methodology. This requirement is problematic as it does not reflect current regulatory requirements or best management practices for MWCs. In addition, it will be very costly and while failing to result in commensurate enhancements in reporting accuracy. Further, the GHG emission calculation methodology imposed on MWCs is out of proportion to the sector's relative GHG emissions when compared to other electricity generators. As we note below, other GHG reporting programs allow MWCs to use the Tier 2 calculation methodology. In fact, EPA proposes in the MRR to allow fossil fuel-fired, stationary combustion sources with far greater GHG emissions than MWCs to use the Tier 2 calculation methodology. We urge the Agency to reconsider requiring MWCs to use the Tier 4 methodology and recommend that MWCs use a modified Tier 2 methodology analogous to the Title V program methods used for annual reporting of criteria pollutants and hazardous air pollutants (HAP). MWCs, Also Known as Waste To Energy (WTE) Facilities are Very Small Emitters of GHG EPA's most recent national GHG inventory (Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2007, April 2009) reports WTE facilities emit very small amounts of GHG relative to other electricity producing sources. Municipal waste combustors account for only 0.34 percent of total CO_2 equivalent emissions from all Energy Related Activities (20.8 Tg CO_2e from a total of 6170.3 Tg CO_2e from the entire source category) and only 0.55 percent of total CO_2e emissions from the Combustion Source sector in EPA's proposed reporting rule. Based on WTE's relatively small contribution to GHG emissions in their sector, ERC suggests that more flexible and cost effective GHG reporting requirements are appropriate and would result in data of sufficient accuracy and reliability to meet EPA's needs. The Western Climate Initiative Mandatory Reporting Requirements and the U.S. Department of Energy's 1605 (b) Voluntary Reporting Program Employ Tier 2 Calculation Methods The Tier 4 calculation methodology proposed in the mandatory reporting rule is very similar to the initial method proposed in the January 2009 draft Western Climate Initiative (WCI) Mandatory Reporting Requirements. Subsequently in May 2009, after extensive public comments, the WCI concluded that requiring the installation of CEM components for CO_2 and stack gas flow measurement at facilities, which had not previously installed them, was extremely onerous and expensive and would not improve overall reporting accuracy. Accordingly, the WCI adopted a methodology for the General Stationary Combustion category that eliminated the use of 40 CFR Part 75 type CEMS unless a unit was already equipped with both a stack gas volumetric flow rate monitor and a CO_2 CEM. WCI also eliminated the use of Part 75 CEMS for municipal solid waste combustion units and established the use of Tier 2 calculation methodologies. The U.S. Department of Energy (DOE) 1605(b) Voluntary Reporting program offers similar flexibility in its "A-Rated Measurement and Estimation Method" for stationary combustion sources. The DOE approach includes: 1. Use of continuous direct measurement of CO_2 at facilities that have already installed CEMs for CO_2; 2. Use of emission factors based on multiple, regularly repeated, on-site direct measurement of source emissions; and 3. Use of measured source activity data (e.g., amount of MSW processed, steam production) ERC recommends that EPA incorporate similar requirements for municipal waste combustors in the final MMR. As WCI concluded, accurate annual GHG emissions result when using the Tier 2 calculation methodology, including use of actual steam generation or waste throughput data, CO_2 emission factors, heat input to steam output or stack flow rate to steam output ratios, and fuel HHV. The Proposed 250 Tons Per Day (tpd) Threshold for Applying the Tier 4 Methodology to MWCs is Inappropriate and Inequitable EPA is proposing to require MWC units with a maximum rated capacity of greater than 250 tons per day of MSW to use the Tier 4 methodology, while other stationary combustion units of 250 MMBtu/hr may use Tier 2. ERC recommends that the EPA allow large and small capacity MWCs to use the Tier 2 calculation methodologies, particularly as MWCs have significantly lower GHG emissions than the 250 MMBtu/hr combustion sources as shown in Table 1. [See submittal for data table provided by commenter.] It is readily apparent that a 250 ton per day MWC emits only 18 percent of the CO_2 emitted by a 250 MMBtu/hr oil-fired unit or only 25 percent of the CO_2 emitted by a gas-fired combustion unit. Even a larger, 750 ton per day municipal waste combustor emits only 54 percent as much as a 250 MMBtu/hr oil-fired combustion unit and 75 percent as much CO_2 as a 250 MMBtu/hr gas-fired combustion unit. Consequently, a large MWC unit's cost to implement the Tier 4 methodology is disproportionate with respect to their relative GHG emissions. In addition, unlike typical 250 MMBtu combustion units, MWCs are subject to extensive source testing, and requirements to install Part 60 CEMS equipment that provides accurate and reliable GHG reporting. We question the need to impose costly, alternative monitoring equipment on these relatively small sources, particularly when far larger sources may utilize the far less expensive Tier 2 methods.

Response: EPA believes that it is appropriate to require the use of CEMS on the largest MSW combustion sources, provided that all of the criteria in §98.33(b)(4)(ii) or (iii) are met. EPA has kept the 250 ton MSW/day size determination. Both the 250 mmBtu/hr and 250 tons MSW/day are size determinations for considering large sources in other EPA programs (General Stationary Combustion Technical Support Document, EPA-HQ-OAR-2008-0508-0004). These size determinations were not considered to be directly comparable, but rather to reflect consistency with other EPA programs, particularly where the challenge of monitoring is substantially different, as it is for MSW versus more homogenous fossil fuels.

EPA believes that it is appropriate for MSW combustion units to use ASTM D6866-06a and D7459-08 on a quarterly basis to determine the relative proportions of biogenic and non-biogenic CO_2 emissions from the MSW combusted. Where Tier 2 is used, EPA has provided for MSW combustion units to determine total CO_2 emissions from the amount of steam produced, boiler design, and a default CO_2 emission factor. EPA believes that this is more appropriate than determining site-specific factors during annual testing. Where Tier 4 is used, CO_2 emissions are determined using a CO_2 concentration monitor and a stack gas volumetric flow rate monitor. EPA does not believe that it is appropriate to estimate stack flow based on steam production in Tier 4. Biogenic emissions for the MSW combustion unit are then calculated by multiplying the total CO_2 emissions for the year, determined using Tier 2 or 4, by the fraction of biogenic emissions, determined using the ASTM methods.

Commenter Name: Lawrence W. Kavanagh
Commenter Affiliation: American Iron and Steel Institute (AISI)
Document Control Number: EPA-HQ-OAR-2008-0508-0695.1
Comment Excerpt Number: 7

Comment: Tier 2 relies on monthly measured heat values and default emission factors (from Tables C-1 or C-2), and the quantity of fuel combusted based on company records. Tier 3 requires the use of monthly measurements for fuel carbon content, molecular weight, and fuel quantities. However, we believe that both of these requirements are unnecessary and believe that Tier 1 (based on annual emissions and default emission factors) is an acceptable calculation methodology for the following reasons. Requirements for efficient and productive operation of coke ovens and rigid specifications for coke quality dictate a very stable operation – from the blending of coal charged into the oven to heating practices. This means that the chemistry and heating value of coke oven gas and the resulting products of combustion will be fairly consistent over time. Accordingly, if reporting of coke oven combustion stack CO_2 emissions is retained in the final rule, we respectfully request that Tier 1 methodology apply. Total annual CO_2 emissions can be determined with sufficient certainty and accuracy by averaging routine coke oven gas carbon analyses or documented default values and known coke oven gas consumption rates. However, since the frequency and type of sampling and analysis of coke oven gas employed by coke producers varies substantially from company to company, we urge EPA not to specify the sampling frequency in the rule. We believe the incentive for companies to sample and analyze the gas for operational purposes is sufficient for establishing a basis for GHG reporting.

Response: EPA has retained the requirement to use the Tier 3 methodology for large 250 mmBtu/hr units that combust gaseous fuels other than natural gas and biogas. Methodologies that reflect the variability of fuels across units and facilities through sampling and measurement are more accurate than methodologies that do not account for this variability. The gains from measurement vary by fuel type (i.e., heterogeneity of carbon content and heat rate is lower in some fuels) and the final rule accounts for this difference by varying the requirements for units, with due consideration of burden and cost. Process gas potentially has more variability over time, compared to a consistent commercial fuel like natural gas or distillate fuel oil, indicating that Tier 1 would be less accurate than higher tiers. A higher tier for process gases over commercially marketed fuels is consistent with the EU ETS, and CARB program.

The daily sampling requirement has been retained, but only for facilities with existing equipment in place that is capable of providing the data. Otherwise, weekly sampling is required.

Commenter Name: Lawrence W. Kavanagh
Commenter Affiliation: American Iron and Steel Institute (AISI)
Document Control Number: EPA-HQ-OAR-2008-0508-0695.1
Comment Excerpt Number: 5

Comment: If it is EPA's intent to require duplicative reporting of emissions from coke oven combustion stacks, we urge other considerations. Coke ovens are unique and unlike traditional combustion sources such as boilers, incinerators or process heaters. Heat is transferred to the coking chamber of individual ovens indirectly through refractory walls from a combustion chamber or flue. Each oven has multiple burners firing coke oven gas or a blend of coke oven gas and blast furnace gas, and a coke battery contains multiple ovens. Combustion products are collected in a gas main and discharged through a stack serving the entire battery. Since the total heat input at a typical coke battery exceeds 250 MMBTUH for all ovens combined, Subpart C would require the use of Tier 2 or Tier 3 calculation methodology.

Response: EPA intends that the stationary combustion source category include any device that meets the definition included in §98.30 for which emissions are not accounted for in the report through a separate subpart of the rule. Per the requirements in 40 CFR Part 98, Subpart A, facilities have to report GHG emissions from all source categories located at their facility, including stationary combustion and process emissions. EPA does not intend that emissions be double reported, and has revised the various subparts of the final rule to clarify the intent of the stationary combustion source category. EPA understands that if process and combustion emissions are not easily or logically separated, that combustion emissions may be reported in combination with process emissions, as in the case of coke ovens and in the use of blast gas.

EPA has also removed the cumulative 250 mmBtu/hr restriction on unit aggregation, and has clarified the common pipe reporting option for use where a metered pipe serves the same fuel to multiple units.

Commenter Name: Dale Backlund, Regulatory Affairs Leader, The DOW Chemical Company and Victoria Evans, National Practice Leader for Greenhouse Gases, URS Corporation
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2008-0508-1338
Comment Excerpt Number: 5

Comment: The tier system would function more efficiently if EPA were to set emissions thresholds over which individual source emissions were required to be reported under data Tier 3 or Tier 4; below those thresholds, data Tiers 3 or 4 would be optional.

Response: EPA has retained capacity based thresholds as they apply to the use of tiers, but has revised the final rule to allow aggregated reporting for any number of units, each of which has a maximum rated heat input capacity of 250 mmBtu/hr or less. EPA has also increased the flexibility of the tier system, allowing more reporters to use the lower tiers. Tier 4 is not required unless all of the criteria in §98.33(b)(4)(ii) or (iii) are met, and Tier 3 is required only for units with a maximum rated heat input capacity greater than 250 mmBtu/hr meeting the other specified criteria.

Commenter Name: Geoffrey Cullen
Commenter Affiliation: Can Manufacturers Institute (CMI)
Document Control Number: EPA-HQ-OAR-2008-0508-0703.1
Comment Excerpt Number: 5

Comment: For facilities that will be covered by the reporting requirements, CMI supports allowing the use of utility bills to calculate the amount of natural gas combusted.

Response: EPA appreciates your comments and has changed the final rule to allow natural gas-fired units of any size to use Tier 2 calculations, in which company records are used to determine fuel use. A definition of "company records," as it pertains to quantifying fuel consumption, has been added to §98.6. It specifies that fuel billing meters may be used to quantify fuel consumption. Furthermore, the final rule specifies that fuel billing meters may be used to quantify the use of liquid and gaseous fuels in Tier 3.

Commenter Name: Jay M. Dietrich
Commenter Affiliation: IBM
Document Control Number: EPA-HQ-OAR-2008-0508-0978.1
Comment Excerpt Number: 5

Comment: IBM is supportive of the proposed measurement and calculation methods for determining the CO_2 emissions from fuel use. The combustion unit size distinctions are appropriate for IBM operations and the proposed CO_2 emissions calculation methods are reasonable. For fossil liquid fuel, IBM would recommend a variation on the Tier 1 methodology. IBM uses fossil liquid fuel as a back-up fuel to its natural gas supply. Depending on the weather, supply availability and contract requirements, facilities burn varying quantities of fuel during a heating season. Higher heating values (HHVs) are provided by the supplier with each shipment of fuel, and the estimated HHV for the storage tank is calculated on a periodic basis using this data. The proposed recommendation would be to establish a Tier la methodology by which a company could update the HHV value of its storage tank on a monthly basis based on the fuel shipment volumes, the supplier's HHV for the shipment, and the current, calculated HHV value of the tank. Contact Jay Dietrich at idietric@us.ibm.com for additional information on this proposal.

Response: EPA has modified the sampling requirements for oil or other fuels received in lots. Rather than a monthly sample, a representative sample for each shipment or delivery is now required, and the final rule clarifies that fuel sampling and analysis data provided by the supplier may be used in the emission calculations.

Commenter Name: Chris Greissing
Commenter Affiliation: Industrial Minerals Association - North America (IMA-NA)
Document Control Number: EPA-HQ-OAR-2008-0508-0705.1
Comment Excerpt Number: 5

Comment: The manner in which the proposed rule is currently drafted, it is unclear whether all of the described conditions must be applicable before the Tier 4 Calculation is mandatory, or if just a single condition is all that is necessary. This language should be clarified. We would also request that all of the described conditions must be applicable before Tier 4 Calculation is mandatory. If only one condition is necessary, this would result in potentially huge costs to the industry, as continuous emissions monitoring systems are extremely expensive to install. IMA-NA proposes the following language be inserted at §98.33 (b)(5)(ii) of the proposed rule: "Shall be used for a unit if all of the conditions below are met:"

Response: EPA acknowledges the commenters' concerns regarding Tier 4 applicability. EPA has revised §98.33(b)(4)(ii) of the final rule to clarify that all six criteria specified in subparagraphs (A) through (F) must be met before Tier 4 is required.

Commenter Name: H. Allen Faulkner
Commenter Affiliation: Ascend Performance Materials, LLC, Decatur Plant
Document Control Number: EPA-HQ-OAR-2008-0508-1578
Comment Excerpt Number: 5

Comment: Ascend Decatur facility uses the following method for determining the coal usage for the site's boilers and coking units: (1) Monthly physical coal inventory taken via coal yard and bunker observations; (2) Daily BTU output and coke production yields are reconciled monthly; (3) Removal of coal used during month is taken from accounting closure; (4) Annual physical coal inventory is taken at 12 noon on September 30 of each year by way of a flyover; and (5) Monthly reconciliation is based on usage, bunkers and coal deliveries. While this method has proven to be extremely accurate, it is subjective and does not rely on weighing equipment or fuel flow meters. Therefore, calibrations are not practical. Ascend is requesting that the current language be revised to be less restrictive and allow a facility to use methods such as described above.

Response: EPA has retained the provisions in Tier 3 allowing facilities to determine solid fuel combustion using company records for the purposes of Tier 3 calculations. EPA has defined the term "company records" in §98.6 of the final rule, and believes that the revised definition provides appropriate guidance as to what records a facility may use to determine fuel consumption. EPA believes that these provisions provide an appropriate balance between reducing the reporting burden and gathering accurate data.

Commenter Name: H. Allen Faulkner
Commenter Affiliation: Ascend Performance Materials, LLC, Decatur Plant
Document Control Number: EPA-HQ-OAR-2008-0508-1578
Comment Excerpt Number: 4

Comment: Ascend Decatur Alabama Plant combusts several chemical byproduct wastes, generated on-site, as fuels in stationary fuel combustion units. 98.33(c)(4) requires a site to develop site specific CH_4 and N_2O emission factors for each fuel. Ascend is requesting that EPA develop guidance for the development of these factors. Are factors based on process conditions, chemistry and thermodynamics sufficient and acceptable or would source testing be required?

Response: EPA acknowledges the commenter's concerns, and has revised the rule to state that any fuels for which default emission factors are not provided can be excluded from calculations of CH_4 and N_2O. EPA is no longer requiring facilities which combust other fuels to develop site-specific emission factors, and thus does not believe it is necessary to provide any guidance in this matter.

Commenter Name: Thomas M. Ward
Commenter Affiliation: Novelis Corporation
Document Control Number: EPA-HQ-OAR-2008-0508-0561.1
Comment Excerpt Number: 6

Comment: The use of fuel-specific emission factors for fuel combustion sources is sufficient to meet the goals and objectives of the reporting protocol and should be incorporated in the proposed rule. Since EPA has already developed and established such a reporting mechanism under the Climate Leaders program (i.e. Stationary Source Combustion Guidance) that has been successfully used by a collection of industries for most of the past decade, it is reasonable to adopt this proven approach here as well. Accordingly, EPA should incorporate the Climate Leaders stationary combustion source reporting guidance in the mandatory GHG reporting program for three important reasons: (1) it provides a suitable technical means to ensure continuity of data for reporting that is accurate and cost-effective; (2) it provides continuity with the industries that have been reporting and will continue to report under the Climate Leaders program, and thereby reduce reporting confusion that might come with enacting differing reporting and recordkeeping requirements. (3) it is consistent with international reporting requirements. In summary, Novelis supports adoption of Climate Leaders protocol for all the preceding reasons but also to the extent that it is a recognition of the proactive efforts of Climate Leader participants that pursued emission reduction through the implementation of related programs, while not unfairly benefiting those parties or facilities that have chosen not to participate in voluntary beneficial GHG reduction programs.

Response: See the Preamble, Section II. O., for the response on the relationship of this rule to other programs. The reporting requirements under the voluntary Climate Leaders partnership were created in the context of that specific voluntary program, with different goals and requirements than reporting under the Clean Air Act.

See the Preamble, Section II. L., for the response on the general monitoring approach.

EPA did not choose to adopt a simplified calculation method approach (e.g., using default emission factors) for all units because the data would be less accurate than under the selected option and would not make use of site-specific data that many facilities already have available and refined calculation approaches that many facilities are already using. Methodologies that reflect the variability of fuels across units and facilities through sampling and measurement are more accurate than methodologies that do not account for this variability. The gains from measurement vary by fuel type (i.e., heterogeneity of carbon content and heat rate is lower in some fuels) and the final rule accounts for this difference by varying the requirements for units, with due consideration of burden and cost.

Commenter Name: Angela Burckhalter
Commenter Affiliation: Oklahoma Independent Petroleum Association (OIPA)
Document Control Number: EPA-HQ-OAR-2008-0508-0386.1
Comment Excerpt Number: 22

Comment: EPA needs to allow reporters to use best estimates so they don't have to install fuel flow meters on each of their combustion sources.

Response: EPA has considerably revised §98.33(b), describing which tier a reporter is to use. Tier 2, which allows facilities to determine fuel use from company records, is now applicable to units of any size in which the only fossil fuels combusted are pipeline quality natural gas and/or distillate fuel oil. Units with a maximum rated heat input capacity less than 250 mmBtu/hr, combusting any fuel for which default values are provided, may also report using Tier 1 or Tier 2, and may determine fuel use through company records. EPA has defined the term "company records" in §98.6 of the final rule, and believes that the revised definition provides appropriate guidance as to what records a facility may use to determine fuel consumption. While fuel flow meters may be used where company records are required, they are certainly not mandatory. EPA has also clarified in the final rule that fuel billing meters may be used for the purpose of directly measuring combustion of liquid and gaseous fuels in Tier 3. Meanwhile, EPA has retained the provisions in Tier 3 allowing facilities to determine fuel oil consumption using tank drop measurements and solid fuel combustion using company records for the purposes of Tier 3 calculations. EPA believes that these provisions provide an appropriate balance between reducing the reporting burden and gathering accurate data.

Commenter Name: Susan Amodeo Cathey
Commenter Affiliation: Air Liquide USA, LLC
Document Control Number: EPA-HQ-OAR-2008-0508-0464.1
Comment Excerpt Number: 6

Comment: The Proposed Rule defines the emissions calculations deemed by EPA as appropriate for hydrogen production facilities, however, the applicability of which "tier" of calculation method required needs to be clarified. The proposed rule identifies 4 tiers of calculation methods with each successive tier requiring more rigorous requirements. EPA should modify the language in the proposed rule to remove the apparently unintended requirement for all facilities to use the most rigorous Tier 4 calculation method. The proposed language would imply that all affected sources would be required to use the most rigorous calculation method imposed by Tier 4. Instead EPA should clarify that only the most significant of sources (i.e. utilities) should be required to use Tier 4, while other less significant sources (i.e. H_2 plants) should be able to use one of the other, less rigorous calculation methods.

Response: EPA acknowledges the commenters' concerns regarding Tier 4 applicability. EPA has revised the final rule to clarify that all of the criteria specified in §98.33(b)(4)(ii) or (iii) must be met before Tier 4 is required.

Commenter Name: Lorraine Krupa Gershman
Commenter Affiliation: American Chemistry Council (ACC)
Document Control Number: EPA-HQ-OAR-2008-0508-0423.2
Comment Excerpt Number: 40

Comment: EPA has not provided a de minimis threshold below which the greenhouse gas emissions from a stationary combustion source can be determined using simplified emission estimation techniques. The emissions from the de minimis combustion units would still be reported. However, the de minimis exemption would avoid the very costly and unnecessary requirement to install flowmeters and perform frequent monitoring on truly insignificant sources such as comfort hot water heaters, gas furnaces for buildings, gas stoves, etc. ACC recommends that EPA add a de minimis threshold in §98.31 or §98.32 to allow for the use of simplified emission estimates for emissions from equipment whose emissions fall under the threshold which we recommend to be at least 3 MM Btu/hour.

Response: See the Preamble, Section II. K., for the response on de minimis reporting for small emission points.

EPA does not agree that there should be a de minimis emissions exclusion. EPA's general approach across the entire rule was not to establish de minimus thresholds, and to require reporting for any source where methods are given. For data collection for future policies, it is important to understand the full suite of stationary combustion sources and the fuels being consumed regularly at a facility -- future policies could then provide exemptions or not. Setting a minimum heat capacity rating would add unnecessary complexity to the rule because there would need to be additional cumulative limitations on the amount of units that could be exempted under a heat capacity threshold. This is why EPA is allowing aggregation of units for all units < 250 mmBtu/hr with no limitation on the combined heat input capacity of those units (versus a more complex exemption of all units < 10 mmBtu/hr but not in excess of a combined heat input of > 250 mmBtu/hr, for example).

However, the commenter should note that the rule excludes portable equipment, as defined in §98.6, emergency generators and emergency equipment, as defined in §98.6, and irrigation pumps at agricultural operations. Additionally, most units smaller than 250 mmBtu/hr may report using Tier 1 or Tier 2, which do not require fuel flow meters. EPA has also revised the Tier 2 and Tier 3 sampling requirements to reduce the burden on reporters. EPA has also removed the cumulative 250 mmBtu/hr restriction on unit aggregation, and has clarified the use of common pipe metering. EPA believes that the expanded availability of these options will reduce the reporting burden on facilities.

Commenter Name: Jeff A. Myrom
Commenter Affiliation: MidAmerican Energy Holdings Company
Document Control Number: EPA-HQ-OAR-2008-0508-0581.1
Comment Excerpt Number: 29

Comment: MidAmerican believes that using the fuel heating value is reasonable given that it is a test that is much more commonly run on fuels than carbon content.

Response: EPA appreciates the commenter's support, and has significantly expanded the use of the Tier 2 calculation methodology based on fuel heating value for units that combust pipeline quality natural gas and/or distillate oil, in view of the homogeneous nature of these fuels. However, the Tier 3 methodology which includes carbon content measurements is still required for units with a maximum rated heat input capacity greater than 250 mmBtu/hr that combust other fossil fuels.

Commenter Name: Michael DiMauro
Commenter Affiliation: Massachusetts Municipal Wholesale Electric Company (MMWEC)
Document Control Number: EPA-HQ-OAR-2008-0508-0580
Comment Excerpt Number: 5

Comment: If EPA does not establish DeMinimus Thresholds, or if any adopted DeMinimus Threshold only excludes very small units, EPA should allow, as an option, the use of estimation procedures to approximate annual fuel usage in lieu of requiring fuel metering or direct documentation of fuel consumption. Such an estimation methodology might utilize the design heat input of the unit, in conjunction with a typical load and annual operating time to approximate annual fuel consumption or annual heat input. This type of approach should be made available for units of a size up to 20 - 50 MMBtu/hr. It should be noted that the option to aggregate emissions from these small combustion sources does not provide any significant benefit so long as total fuel flows must be directly measured or otherwise directly documented, as this information is typically no easier to obtain on an aggregate level than for an individual unit.

Response: See the Preamble, Section II. K., for the response on de minimis reporting for small emission points.

EPA acknowledges the concerns of the commenter, but believes that the Tier 1 and Tier 2 Calculation Methodologies provide sufficiently simple methods of determining CO_2 emissions from small sources. These methods are based on default emission factors and fuel consumption from company records (they do not require any direct measurements of fuel consumption). The methods are available to units with a maximum rated heat input capacity of less than 250 mmBtu/hr combusting any type of fuel listed in Table C-1 of Subpart C, as well as to units of any size combusting only pipeline quality natural gas, distillate oil, or biogenic fuels listed in Table C-1. EPA believes that the availability of these methods addresses the commenter's concerns. EPA recommends that the commenter check the definition of company records to assess whether or not a particular alternative approach (e.g., estimation procedures) is consistent.

Commenter Name: Ted Michaels
Commenter Affiliation: Energy Recovery Council (ERC)
Document Control Number: EPA-HQ-OAR-2008-0508-0544.1
Comment Excerpt Number: 4

Comment: Alternative Thresholds for Methodologies If EPA decides that thresholds should be used to determine the applicability of the various calculation methodologies, then an alternative threshold for use of Tier 4 for MWCs should be included. An appropriate threshold should be based on non-biogenic CO_2 emissions equivalent to a 250 MMbtu/hr natural gas fired combustion source. Using the emission factors and assumptions in the calculations above, we propose the following: "(5) Tier 4 Calculation Methodology: …(ii) Shall be used if: …, or if the unit combusts municipal solid waste, and if non-biogenic CO_2 emissions are greater than 13,255 kilograms per hour calculated using maximum permitted heat input in MMBtu per hour, Table C-2 default emission factor b nvcb and the non-biogenic fraction from ASTM D 6866-06a results." Section 98.33(b)(5)(ii) Should be Modified to Clarify Conditions Under Which Units Must Use the Tier 4 Calculation Methodology Section 98.33(b)(5)(ii) outlines the conditions under which a reporter must use the Tier 4 calculation methodology to estimate a unit's emissions. As drafted, it lists a series of conditions, (A) through (F), with no conjunctions between conditions. We assume the Agency intends that all conditions must be met for the Tier 4 method to apply. Otherwise, the application of just one condition — the unit has operated for more than 1,000 hours in any calendar year since 2005 — would require the vast majority of stationary combustion units to use Tier 4. We do not believe the EPA intended such a far-reaching result. We urge the EPA to insert the word "and" between each of the conditions to clarify that all conditions must be met before a unit is subject to Tier 4. Further, per our comments above concerning application of Tier 4 to municipal solid waste combustion, we urge the Agency to delete the second half of condition (A) referring to units that combust MSW and have a maximum rated input capacity greater than 250 tons per day of MSW.

Response: EPA acknowledges the commenter's concerns regarding Tier 4 applicability, and has revised §98.33(b)(4)(ii) and (iii) of the final rule to clarify that all specified criteria must be met before Tier 4 is required. However, EPA has kept the 250 ton MSW/day size determination. Both the 250 mmBtu/hr and 250 tons MSW/day are size determinations for considering large sources in other EPA programs (General Stationary Combustion Technical Support Document, EPA-HQ-OAR-2008-0508-0004). These size determinations were not considered to be directly comparable, but rather to reflect consistency with other EPA programs, particularly where the challenge of monitoring is substantially different, as it is for MSW versus more homogenous fossil fuels.

Commenter Name: Scott Evans
Commenter Affiliation: CleanAir Engineering (Clean Air)
Document Control Number: EPA-HQ-OAR-2008-0508-0696.1
Comment Excerpt Number: 3

Comment: We encourage EPA to consider the use of thermodynamic models to determine boiler heat rate. Real-time thermodynamic modeling, in combination with routine plant measurements, can be used to accurately estimate CO_2 emissions. This approach relies on electrical power measurement as the primary Flow measurement, which has the advantage of having significantly lower uncertainty than the fuel and Flue gas Flow measurements employed by other methods. As shown in the attached report [see DCN: EPA-HQ-OAR-2008-0508-0696.2], one of the greatest sources of uncertainty in the calculation approach to GHG estimation is fuel Flow. This is particularly true of solid fuel boilers. Many electric utility boiler operators are turning to thermodynamic modeling as a more accurate means to determine heat rate. The technique employed is to utilize a thermodynamic model of the power plant in which mass and energy are conserved. The model is bounded by measured process conditions that have a direct impact on plant capacity and executed on a real-time basis to predict heat input from fuel and CO_2 production. CO_2 production is a function of the fuel type and quality, which can be indexed on a real-time basis to a known analysis based on routine process measurements to determine the appropriate carbon factor. This step further reduces the uncertainty associated with varying fuel quality. A thermodynamic model may have sufficient fidelity to predict a range of operating parameters, which provides opportunities for independent feedback mechanisms to assure accuracy and repeatability. This method relies on measurement of the product being sold, electricity, which for practical and financial reasons, receives greater attention from instrument and control personnel. Furthermore, the measurement of electricity has the least uncertainty of all the primary "Flows" in a power plant. This approach combined with site-specific (not generic) emission factors or fuel carbon content, will likely provide more reliable GHG emission data than with the fuel-Flow/generic emission factor approach. We feel this approach is definitely more accurate than Tier 2, however, at this time, we do not have data to support its inclusion in Tier 4. Therefore, we feel the most appropriate classification would be in Tier 3 (assuming use of a site specific emission factor or fuel carbon content).

Response: EPA's approach makes use of existing data and methodologies to the extent feasible, and is consistent with the types of methods contained in other GHG reporting programs (e.g., the California mandatory reporting rule, WCI, RGGI, TCR, and Climate Leaders). Because this approach specifies methods for each source category, it will result in data that are comparable across facilities. The Agency is not opposed to innovative, alternative approaches for CO_2 emissions calculation, such as the thermodynamic modeling described by the commenter. However, the commenter did not provide any supplementary information, proposed rule language, or cost analysis to explain how this proposed methodology could be implemented. In view of this, EPA has not incorporated the commenter's suggested approach into the final rule, but is willing to consider it in a future rulemaking, if the necessary technical details of the method are provided for Agency review.

Commenter Name: Thomas M. Ward
Commenter Affiliation: Novelis Corporation
Document Control Number: EPA-HQ-OAR-2008-0508-0561.1
Comment Excerpt Number: 3

Comment: Tiered Reporting Protocol: Although Novelis Corp. agrees that the GHG reporting rule should include direct emissions from significant combustion sources within a facility, it has some concerns with the approach proposed in the rule. Specifically, the proposed tiered reporting protocol included is overly complex and burdensome. In effect, many facilities with various sized combustion units will have to comply with an array of reporting tiers at the process unit level that are extremely complex and expensive to conduct. Reporting at a unit level is unduly costly and burdensome and grouping systems may not be feasible due to logistics and the cost of metering. The difference in measured values between the main billing meter and any unit and/or grouped measures would serve to adequately quantify such units to reduce cost the cost burden associated with additional measuring equipment.

Response: See the Preamble, Section II. L., for the response on the general monitoring approach.

See the Preamble and the response to comment EPA-HQ-OAR-2008-0508-0520.1 excerpt 16 for the rationale for level of reporting and the additional flexibility provided to reporters, particularly for common pipe and aggregated unit circumstances.

EPA does not agree with the commenter's assertion that the amount of unit-level data and verification information to be reported is excessive, burdensome, or unnecessary. For this mandatory GHG emissions reporting rule, two main approaches to data verification were considered, i.e., EPA verification and third-party verification. The Agency decided on the former approach. In view of this, additional, unit-level information is deemed necessary to provide assurance that the reported facility-wide GHG emissions data are both credible and accurate.

However, EPA has modified the rule to make it clearer the conditions under which specific tiers should be used. EPA has also dropped the cumulative 250 mmBtu/hr heat input capacity limit on the aggregation of units. Rather, the 250 mmBtu/hr restriction applies only to the individual units in the group. Therefore, for reporting purposes, individual units with maximum rated heat input capacities of 250 mmBtu/hr or less may be aggregated without limit into a single group, provided that the Tier 4 methodology is not required for any of the units, and all units in the group use the same tier for any common fuel(s) that they combust. Units with maximum rated heat inputs greater than 250 mmBtu/hr using Tiers 1, 2, and 3 must report as individual units, unless they burn the same type of fuel, and the fuel is provided by a common pipe or supply line; in that case, the owner or operator may opt to use the common pipe reporting provisions in §98.36(c)(3). Units using Tier 4 must report as individual units unless they share a monitored common stack or duct; in that case, the common stack or duct reporting provisions may be used. The commenter should note that Tiers 1 and 2, which have been expanded to include units of any size in which the only fossil fuels combusted are pipeline quality natural gas and/or distillate oil, do not require fuel metering but instead rely on company records to quantify fuel consumption.

Commenter Name: Blair Wheeler
Commenter Affiliation: Aspen Technology, Inc.
Document Control Number: EPA-HQ-OAR-2008-0508-0488.2
Comment Excerpt Number: 2

Comment: In Subsection 7.1 Stationary Combustion Sources, we propose adding an additional option (Option 5) that would be based on direct measurement (minute or hour) and calculation of carbon emissions based upon fuel type, fuel flow, exhaust stack temperature and stack gas excess oxygen utilizing a steady state engineering model specific to that process unit. However, based upon our real world experience, this carbon emission calculation must be verified with an energy balance (compare fired side heat release with process or steam side heat absorption) around the Stationary Combustion Source to ensure the most accurate calculation of carbon emissions. If the heat balance is off more than a predetermined percentage or absolute amount, the system should notify the refinery staff for timely investigation of the cause and correction (i.e., instrument recalibration).

Response: EPA's approach makes use of existing data and methodologies to the extent feasible, and is consistent with the types of methods contained in other GHG reporting programs (e.g., the California mandatory reporting rule, WCI, RGGI, TCR, and Climate Leaders). Because this approach specifies methods for each source category, it will result in data that are comparable across facilities. The Agency is not opposed to innovative, alternative approaches for CO_2 emissions calculation, such as the one described by the commenter. However, the commenter did not provide any supplementary information, proposed rule language, or cost analysis to explain how the proposed methodology could be implemented. In view of this, EPA has not incorporated the commenter's suggested approach into the final rule, but is willing to consider it in a future rulemaking, if the necessary technical details of the method are provided for Agency review.

Commenter Name: W. Walter Tyler
Commenter Affiliation: INVISTA S.a r.l. (INVISTA)
Document Control Number: EPA-HQ-OAR-2008-0508-0481.2
Comment Excerpt Number: 2

Comment: Tier I methodology for all reporting facilities will provide a reasonable level of certainty and accuracy. Like many other companies, INVISTA has taken steps to determine estimates of total GHG emissions through established industry standards and protocols that utilize fuel consumption data and recognized emission factors. For example, the Climate Registry (TCR), the WRI/WBCSD and ISO 14064.1 standards and protocols utilize well-recognized and well-established default emission factors for estimating GHG emissions that are comparable to the proposed methodology in Tier 1 of the Proposed Rule. This data has shown to be a reliable indicator, not only for tracking inventory and product manufacturing costs, but also in some instances for emissions estimates needed under other environmental regulatory programs, such as the Clean Air Act's Title V program. The Proposed Rule, however, specifies a 4-Tier reporting structure that is much more complex than other GHG reporting systems. The requirements in the Proposed Rule – including enhanced direct emissions monitoring, total carbon content analysis, and fuel-flow meters – demand significant additional investments at manufacturing sites with little gain in accuracy of emissions estimates over that which can be obtained by using current, accepted industry practice. In addition, the Tier 3 and 4 categories require an unspecified level of precision and accuracy to estimate and report GHG emissions based upon devices, measurements, or data that either do not exist currently at many facilities or have not been used historically for reporting or compliance purposes. For example, many facilities subject to this rule back-calculate fuel usage based on accepted industry standards and techniques such as inventory reconciliation, steam flow, or process knowledge which have been used for other reporting and accounting purposes. If EPA determines that this proposed Tiered approach is the preferred vehicle for reporting, then INVISTA recommends that EPA clarify that current industry standards and practice, such as inventory reconciliation, are within the meaning and intent of "company records" upon which many of the emission calculations in the Proposed Rule are based. However, simplifying the current scheme and basing it on recognized reporting methodologies, such as default emission factors, will alleviate much of the uncertainty in the Rule while sacrificing little if any of the accuracy EPA hopes to achieve in this reporting scheme. For these reasons, INVISTA recommends that Tier I methodology be adopted for all source categories.

Response: See the Preamble, Section II. L., for the response on the general monitoring approach.

EPA did not choose to adopt a simplified calculation method approach (e.g., using default emission factors) for all units because the data would be less accurate than under the selected option and would not make use of site-specific data that many facilities already have available and refined calculation approaches that many facilities are already using.

Methodologies that reflect the variability of fuels across units and facilities through sampling and measurement are more accurate than methodologies that do not account for this variability (e.g., Tier 1). The gains from measurement vary by fuel type (i.e., heterogeneity of carbon content and heat rate is lower in some fuels) and the final rule accounts for this difference by varying the requirements for units, with due consideration of burden and cost.

EPA has significantly expanded the use of Tier 1 and Tier 2 Calculation Methodologies. The 250 mmBtu/hr restriction on the use of Tier 2 has been lifted for units in which the only fossil fuels combusted are natural gas and/or distillate oil, in view of the homogeneous nature of these fuels. Most units combusting the biogenic fuels in Table C-1 may use Tier 1. However, the 250 mmBtu/hr unit size cutoff remains for units that combust other fuels. EPA has considerably revised the Tier 2 and Tier 3 fuel sampling requirements in an effort to reduce the burden on reporters. Furthermore, the final rule clarifies that fuel sampling and analysis data provided by the supplier may be used in the emission calculations, and that fuel billing meters may be used to quantify fuel consumption.

EPA has defined the term "company records" in §98.6 of the final rule. EPA believes that the revised definition provides appropriate guidance as to what records a facility may use to determine fuel consumption.

Commenter Name: Stephen E. Woock
Commenter Affiliation: Weyerhaeuser Company
Document Control Number: EPA-HQ-OAR-2008-0508-0451.1
Comment Excerpt Number: 23

Comment: Weyerhaeuser proposes that the CO_2 calculation methodology used for municipal solid waste (MSW) combustion units should be allowed for Tier 3 combustion sources. Currently the MSW CO_2 calculation methodology is only allowed for Tier 2 combustion units, which applies to sources rated at ~ 250 mmBtu/hr in heat capacity. Tier 3 sources are defined as > 250 mmBtu/hr. However, all of the elements within the MSW CO_2 calculation equation are entirely independent of the combustion unit size. EPA illustrates this independence from combustion unit size in the MSW equation for CH_4 and N_2O emissions, which is used for all Tier 1, Tier 2 and Tier 3 combustion units. The MSW CO_2 equation is the same equation as the CH_4 and N_2O emissions, except for the different CO_2, CH_4 and N_2O emission factors. Therefore, since the MSW CH_4 and N_2O equations are suitable for all combustion units, the MSW CO_2 calculation methodology should be allowed for all combustion unit sizes, including Tier 3 combustion units.

Response: EPA has revised the rule to allow the use of steam production and combustion unit efficiency to calculate CO_2 emissions under Tier 2 for other solid fuels in addition to municipal solid waste (MSW). However, EPA does not believe that it is appropriate to calculate emissions using the Tier 2 MSW equation for units that are required to use Tier 3. Given the nature of MSW, the fuel sampling presents a much greater challenge than for many other combustion sources. The Tier 3 methodologies for units with a maximum rated heat input capacity greater than 250 mmBtu/hr that combusts any type of fuel listed in Table C-1 are considered to provide better information than the Tier 2 methodology for MSW. Also the comparison of CO_2 requirements to CH_4 and N_2O requirements is not appropriate given the much lower level and significance of CH_4 and N_2O emissions from stationary combustion.

Commenter Name: Lorraine Krupa Gershman
Commenter Affiliation: American Chemistry Council (ACC)
Document Control Number: EPA-HQ-OAR-2008-0508-0423.2
Comment Excerpt Number: 52

Comment: The Tier 4 calculation methodology requires a "stack gas volumetric flow rate monitor" (§98.33(a)(4)(i)). Many existing CEMS systems determine stack gas flow rate through methods other than direct measurement of the exhaust stream. The requirement to install volumetric flow rate monitors introduces an unnecessary cost and in many cases requires a complete redesign of the stack in order to position a meter properly. The final rule should allow calculation of the stack gas flow rate based on other methodologies. One method that should be allowed involves calculation of the stack flow based on measurement of the oxygen concentration in the stack, fuel flows, and temperature. Another method involves applying an air feed to exhaust flow ratio established through testing. This improvement will encourage facilities that have non CO_2 CEMS systems currently in place to enhance their system to measure CO_2. Requiring a stack gas volumetric flow rate monitor in order to use a CO_2 CEMS is a significant deterrent from voluntary use of the Tier 4 method.

Response: The Tier 4 CEMS requirement is limited to larger solid fossil fuel-fired units and MWC units that have an existing gas monitor of any kind or a volumetric flow rate monitor, or both. EPA is requiring the use of CEMS due to the complexity of monitoring solid fuel consumption and the heterogeneous nature of the solid fuels. The Agency does not agree that the addition of a flow monitor will be excessively costly at an installation where there is an established CEMS infrastructure in place. Redesign of the stack will be not be required "in many cases," as asserted by the commenter. There are a number of different types of flow monitors available commercially. One of the simplest is a differential pressure monitor, consisting of one or more S-type pitot tube sensing elements. This type of monitoring system is relatively inexpensive and can easily be installed on most existing stacks.

Commenter Name: Stephen E. Woock
Commenter Affiliation: Weyerhaeuser Company
Document Control Number: EPA-HQ-OAR-2008-0508-0451.1
Comment Excerpt Number: 22

Comment: Weyerhaeuser proposes that the CO_2 calculation methodology EPA proposes at §98.33(a)(2)(iii) for municipal solid waste (MSW) combustion units should also apply to other solid fuel combustion units. The MSW CO_2 calculation methodology is based on the steam generated to calculate the CO_2 emissions. This steam approach provides an accurate and streamlined approach to calculate the CO_2 emissions, primarily because it eliminates the need to measure fuel usage directly. All solid fuel boilers operate similarly with respect to fuel-steam balance, therefore, the steam approach can be used to calculate the CO_2 from all solid fuel combustion units, such as coal and solid biomass fuels (e.g. wood bark). This accurate approach is already in use for many solid fuel boilers at Weyerhaeuser and in the Forest Products Industry in general. For boilers that use multiple fuels, the proposed rule is very clear as to how to track all of the non-solid fuels. The non-solid fuels are to be measured directly. Therefore, the steam generated by these fuels is easily and accurately determined using standard heat balance equations, which are similar to the MSW equation in this proposed rule. Therefore, the steam not generated by the non-solid fuels is generated by the solid fuels. This streamlined approach ensures the heat balance around the combustion unit is always in balance. This approach also eliminates the inaccuracies of having to measure the moisture content of the solid fuels, because the results from this approach are reported in units of dry material combusted. This is very important when combusting materials such as wood bark, which can have moisture contents ranging from 10% to over 50%, which is very difficult to measure accurately. Therefore, use of the proposed MSW CO_2 calculation methodology should be allowed for all combustion units that use solid fuels, whether it is MSW or other solid fuels. This methodology provides an accurate and streamlined calculation option for the reporters.

Response: EPA has revised the rule to allow the use of steam production and combustion unit efficiency to calculate CO_2 emissions under Tier 2 for other solid fuels in addition to municipal solid waste (MSW). These parameters may also be used to quantify the amount of solid biomass combusted in a unit for the use in Tier 1 calculations.

Commenter Name: Lorraine Krupa Gershman
Commenter Affiliation: American Chemistry Council (ACC)
Document Control Number: EPA-HQ-OAR-2008-0508-0423.2
Comment Excerpt Number: 53

Comment: In §98.33(b)(1), we believe that it is unnecessarily restrictive to limit the use of Tier 1 to units ~ 250 mmBTU/hr in size. EPA has not provided an explanation for this restriction and we recommend that it be deleted in the final rule. The variations introduced in the calculations will be very small compared to the size of the entire greenhouse gas inventory.

Response: EPA disagrees with the commenter's suggestion of allowing Tier 1 reporting for fossil fuel-fired units with a maximum rated heat input capacity greater than 250 mmBtu/hr. EPA did not choose to adopt a simplified calculation method approach (e.g., using default emission factors) for all units because the data would be less accurate than under the selected option and would not make use of site-specific data that many facilities already have available and refined calculation approaches that many facilities are already using.

EPA's approach is to require the larger units to use the more accurate methodologies as part of an effort to balance accuracy of reported data with burden. The 250 mmBtu/hr cutoff is used by other EPA programs to denote larger units (e.g., NO_x Budget Trading Program). Methodologies that reflect the variability of fuels across units and facilities through sampling and measurement are more accurate than methodologies that do not account for this variability. The gains from measurement vary by fuel type (i.e., heterogeneity of carbon content and heat rate is lower in some fuels) and the final rule accounts for this difference by varying the requirements for units, with due consideration of burden and cost.

Commenter Name: William Fred Durham
Commenter Affiliation: West Virginia Department of Environmental Protection (DEP)
Document Control Number: EPA-HQ-OAR-2008-0508-0629.1
Comment Excerpt Number: 3

Comment: Recently, a question came up regarding the root source of the emission factors and high heat values listed in EPA's Proposed MRR, Subpart C – General Stationary Fuel Combustion Sources, Table C-1. The reference for the factors is contained in the Technical Support Document for Stationary Fuel Combustion Emissions: Proposed Rule for Mandatory Reporting of Greenhouse Gases. Regarding the Tier 1 Methodology on page 15, the document states, "Default fuel-specific high heat values and CO_2 emission factors are compiled in Appendix D." Appendix D does not exist; the values are listed in Appendix C, Default CO_2 Emission Factors and High Heat Values for Various Types of Fuel. Further, when Appendix C is investigated it is found that heat values in question are from the draft U.S. EPA, Inventory of Greenhouse Gas Emissions and Sinks: 1990 - 2005 (2007). The DAQ questions if EPA's use of a draft document as a reference is sufficiently robust for its final rule.

Response: EPA appreciates the comment, and acknowledges that the Technical Support Document for Stationary Fuel Combustion Sources incorrectly referred to Appendix D. The fuel-specific high heat values and CO_2 emission factors are from the draft U.S. EPA, Inventory of Greenhouse Gas Emissions and Sinks: 1990 – 2005 (2007) which is a published document from EPA. EPA believes the values in this document can be referenced by the rule. However, the commenter should note that EPA has reviewed and revised the emission factors provided in Subpart C of the rule, in an effort to ensure that they are as appropriate as possible for the purposes of this reporting rule.

Commenter Name: Michael DiMauro
Commenter Affiliation: Massachusetts Municipal Wholesale Electric Company (MMWEC)
Document Control Number: EPA-HQ-OAR-2008-0508-0580
Comment Excerpt Number: 3

Comment: For very small and/or low utilization stationary combustion units, the Rule should provide either: (a) an exclusion from GHG Reporting; or (b) a simplified procedure for determining GHG emissions that does not require direct documentation of fuel usage based on fuel metering or fuel consumption records. The Preamble to the Proposed Rule seems to indicate support for the use of simplified estimation procedures to determine fuel usage ["small stationary combustion units could use a default emission factor and a heat rate to estimate emissions, and no fuel measurements would be required" (FR page 16473 Column 3)], which would obviate the need to obtain data (records or monitoring) directly documenting fuel consumption. However none of the Four Tiers appears to allow the option of relying on a "heat rate" in lieu of fuel records or fuel measurements to estimate fuel consumption for small combustion units. Examples of the types of combustion units that should be eligible to adopt simplified CO_2 emission estimation methods, or should qualify for an exemption from GHG Reporting, include: 1. Small diesels (~ 5 MMBtu/hr) engines whose sole function is to provide start-up power for a Combustion Turbine. This arrangement provides the facility black start capability. The total operating time of the starter diesel at each startup of the combustion turbine is < 15 minutes. These starter diesel engines are not equipped with a fuel meter, and fuel records cannot be used to determine fuel usage, as the oil storage tank is refilled only rarely due to the very limited operating time of the engine. Requiring direct fuel monitoring for such a limited use, small emission unit is unwarranted. 2. Auxiliary Boilers - Many EGU sites have installed small house boilers, in the size range of 10 - 50 MMBtu/hr, to provide heating for the facility during periods the EGU units are not operating (i.e. intervals when the EGUs are not dispatched, or are in an outage). Fuel metering for such house boilers may be crude, data recording is typically on hardcopy charts (which does not allows convenient fuel usage summation). Additionally, segregation of fuel usage for these units based on fuel records may be problematic. Oftentimes, then, fuel metering is poorer and fuel records less available or of lower quality for smaller units than for larger more regulated units, and consequently it can take significantly more effort to obtain reasonable fuel data for smaller units.

Response: See the Preamble, Section II. K., for the response on de minimis reporting for small emission points.

EPA acknowledges the concerns of the commenters, but believes that the Tier 1 and Tier 2 Calculation Methodologies provide sufficiently simple methods of determining CO_2 emissions from small sources. These methods are based on default emission factors and fuel consumption from company records (they do not require any direct measurements of fuel consumption). They are available to units with a maximum rated heat input capacity of less than 250 mmBtu/hr combusting any type of fuel listed in Table C-1 of Subpart C, as well as to units of any size combusting only pipeline quality natural gas, distillate oil, or biogenic fuels listed in Table C-1. EPA believes that the availability of these methods addresses the commenter's' concerns. The commenter should note that the term "company records" is defined in §98.6, and provides guidance as to what fuel use records are acceptable for the purposes of this reporting rule.

Commenter Name: Vince Brisini
Commenter Affiliation: RRI Energy Inc. (RRI)
Document Control Number: EPA-HQ-OAR-2008-0508-0618.1
Comment Excerpt Number: 2

Comment: In order to avoid an unnecessary burden on reporters, US. EPA should offer flexibility with respect to carbon sampling of fuels, as required in Tier 3 data standards. Due to the minor variability in carbon content of pipeline natural gas and fuel oils used by electricity generators, U.S. EPA would not gain a significant amount of accuracy in GHG emissions estimates through carbon sampling of these fuels. Consequently, RRI proposes that U.S. EPA either make Tier 3 methodology optional (i.e., allow reporters to use either Tier 2 or Tier 3 methodology), or ask fuel suppliers—who are already required to submit high heating value (HMV) data to their customers—to also submit data on the carbon content of their fuels.

Response: Some fuel suppliers may report carbon sampling results as part of the requirements under other subparts. Note that EPA is not finalizing Subpart KK (Coal Suppliers) as part of this final rule. EPA has expanded the use of the Tier 2 Calculation Methodology based on fuel heating value to units of any size in which the only fossil fuels combusted are pipeline quality natural gas and distillate oil, in view of the homogeneous nature of these fuels. The number of reporters required to use Tier 3 will be reduced as a result.

The Tier 3 methodology which includes carbon content measurements is still required for units with a maximum rated heat input capacity greater than 250 mmBtu/hr fuels other than MSW. Methodologies that reflect the variability of fuels across units and facilities through sampling and measurement are more accurate than methodologies that do not account for this variability. The gains from measurement vary by fuel type (i.e., heterogeneity of carbon content and heat rate is lower in some fuels) and the final rule accounts for this difference by varying the requirements for units, with due consideration of burden and cost.

The final rule also clarifies that fuel sampling and analysis data provided by the supplier may be used in the emission calculations. The commenter should note that fuel sampling frequencies for Tiers 2 and 3 have been substantially revised: natural gas must be sampled semiannually, and fuel oil must be sampled once per fuel lot.

Commenter Name: Michael DiMauro
Commenter Affiliation: Massachusetts Municipal Wholesale Electric Company (MMWEC)
Document Control Number: EPA-HQ-OAR-2008-0508-0580
Comment Excerpt Number: 2

Comment: While the Part 98 Subpart C and D monitoring provisions provide significant flexibility for Stationary Combustion sources, an approach which is which is strongly supported, monitoring requirements should be simplified, streamlined and more appropriately targeted, and the rule should allow, as an option, more general use of the established Part 75 procedures and calculation methods.

Response: EPA believes that the structure of the final rule to a large extent mirrors this suggestion. The owner or operator of a unit may elect to use a higher tier than required, allowing any units to use Part 75 methodologies under Tier 4. Furthermore, in the final rule EPA has provided alternative methods for units not subject to the Acid Rain Program, but which report data to EPA under Part 75 (see §98.33(a)(5)). These alternative approaches rely heavily on Part 75 methods.

Commenter Name: Kerry Kelly
Commenter Affiliation: Waste Management (WM)
Document Control Number: EPA-HQ-OAR-2008-0508-0376.1
Comment Excerpt Number: 4

Comment: EPA is proposing to require MWC units with a maximum rated capacity of greater than 250 tons per day of MSW to use the Tier 4 methodology, while other stationary combustion units of 250 MMBtu/hr may use Tier 2. WM recommends that the EPA allow large and small capacity MWCs to use the Tier 2 calculation methodologies, particularly as MWCs have significantly lower GHG emissions than the 250 MMBtu/hr combustion sources as shown below in Table 1. [See DCN: EPA-HQ-OAR-2008-0508-0376.1, Table 1, p.4.] It is readily apparent that a 250 ton per day MWC emits only 18 percent of the CO_2 emitted by a 250 MMBtu/hr oil-fired unit or only 25 percent of the CO_2 emitted by a gas-fired combustion unit. Even a larger, 750 ton per day municipal waste combustor emits only 54 percent as much as a 250 MMBtu/hr oil-fired combustion unit and 75 percent as much CO_2 as a 250 MMBtu/hr gas-fired combustion unit. Consequently, a large MWC unit's cost to implement the Tier 4 methodology is disproportionate with respect to their relative GHG emissions. In addition, unlike typical 250 MMBtu combustion units, MWCs are subject to extensive source testing, and requirements to install Part 60 CEMS equipment that provides accurate and reliable GHG reporting. We question the need to impose costly, alternative monitoring equipment on these relatively small sources, particularly when far larger sources may utilize the far less expensive Tier 2 methods.

Response: See the response to comment EPA-HQ-OAR-2008-0508-0544.1, excerpt number 4.

Commenter Name: Michael E. Van Brunt
Commenter Affiliation: Covanta Energy Corporation
Document Control Number: EPA-HQ-OAR-2008-0508-0548.1
Comment Excerpt Number: 4

Comment: Under the Clean Air Act, the EfW industry is subject to rigorous monitoring and reporting requirements, including Continuous Emission Monitoring Systems (CEMS), and extensive pollution control requirements. Adding additional monitoring equipment, in the form of CO_2 and flow CEMS would increase the regulatory burden without a commensurate increase in the quality of CO_2 data. According to the 2009 EPA GHG Inventory, EfW represents less than 0.3% of the total emissions; however, even this number is an overstatement. Comments provided to the EPA over the past three years have indentified that EfW emissions over overstated by a factor of roughly two. Based on the corrected emissions figure, emissions from landfills alone are nearly thirteen times as great as emissions from EfW. In lieu of requiring the installation of new equipment with little additional benefit, we request that the EPA establish two revised Tier 4 methodologies for the EfW industry, both based on current stack testing and/or CEMS requirements. Similar methodologies are expected to be included in The Climate Registry's Electric Power Sector Protocol as an improvement over the emission factor (Tier 2) approach. The first method would allow operators to calculate annual CO_2 emissions based on annual stack testing. Operators would calculate an average fossil & biogenic CO_2 emission rate per unit of steam production based on average CO_2 concentration, stack flow, and steam flow over the test period. This average, when applied to the annual steam production from MSW combusted for a unit and/or facility, would yield the total CO_2 emissions for the year. In the second method, operators would calculate an average stack flow per unit of steam production during annual source testing. Hourly mass flow of CO_2 emissions would be calculated from the following: 1. Calculated stack flow based on the relationship established during the annual stack test and the actual MSW-based steam output; and 2. Hourly CO_2 concentrations. CO_2 concentrations can either be measured directly using a CO_2 CEM, or can be calculated from an O_2 CEM where annual source testing has demonstrated that CO_2 concentrations calculated from the O_2 readings meet the Relative Accuracy Test Audit (RATA) requirements in 40 CFR, Appendix B, Performance Specification 3. The calculation of CO_2 from O_2 can be completed using equations F-14a or F-14b from Appendix F of 40 CFR 75, exactly as applied in the proposed rule to other stationary combustion sources, together with the Fd and Fc F-factors for Municipal Solid Waste (MSW) from Table 19-2 of EPA Method 19. Method 19 is specifically referenced by the emission standards for Municipal Waste Combustors found in 40 CFR 60, Subparts Cb and Eb. Consistent with the Proposed Rule, emissions of anthropogenic CO_2 would then be calculated by applying the annual average of quarterly analysis via ASTM method D-6866-06a of stack samples collected in accordance with ASTM method D7459-08. We fully support the inclusion of quarterly analysis via ASTM method D6866-06a of stack samples collected in accordance with ASTM method D7459-08 to determine the split between anthropogenic and biogenic carbon in §98.33(e)(3). We agree with the EPA's conclusion that a manual sorting approach is not practical, and ASTM methods are more rigorous. Covanta has significant experience with this methodology, having collected nearly 200 samples from sixteen facilities located across the United States.

Response: See the response to comment EPA-HQ-OAR-2008-0508-0544.1 excerpt 4.

EPA believes that it is appropriate to require the use of CEMS on the largest MSW combustion sources and any smaller MSW combustion source which already has CO_2 concentration monitors and stack gas volumetric flow rate monitors in place. EPA has, however, clarified that all of the criteria in §98.33(b)(4)(ii) or (iii) must be present to require the use of Tier 4. EPA believes that it is appropriate for MSW combustion units to use ASTM D6866-06a and D7459-08 on a quarterly basis to determine the relative proportions of biogenic and non-biogenic CO_2 emissions from the MSW combusted. Where Tier 2 is used, EPA has provided for MSW combustion units to determine total CO_2 emissions from the amount of steam produced, boiler design, and a default CO_2 emission factor. EPA believes that this is more appropriate than determining site-specific factors during annual testing. Where Tier 4 is used, CO_2 emissions are determined using a CO_2 concentration monitor and a stack gas volumetric flow rate monitor. EPA does not believe that it is appropriate to estimate stack flow based on steam production in Tier 4, and does not believe it is appropriate to use an O_2 monitor for MSW combustion, since it is not a fuel listed in Table 1 in Section 3.3.5 of Appendix F to Part 75. Biogenic emissions for the MSW combustion unit are then calculated by multiplying the total CO_2 emissions for the year, determined using Tier 2 or 4, by the fraction of biogenic emissions, determined using the ASTM methods. EPA appreciates the commenter's support of the ASTM D6866-06a and D7459-08 methods.

Commenter Name: Kerry Kelly
Commenter Affiliation: Waste Management (WM)
Document Control Number: EPA-HQ-OAR-2008-0508-0376.1
Comment Excerpt Number: 3

Comment: The Tier 4 calculation methodology proposed in the mandatory reporting rule is very similar to the initial method proposed in the January 2009 draft Western Climate Initiative (WCI) Mandatory Reporting Requirements. Subsequently in May 2009, after extensive public comments, the WCI concluded that requiring the installation of CEM components for CO_2 and stack gas flow measurement at facilities, which had not previously installed them, was extremely onerous and expensive and would not improve overall reporting accuracy. Accordingly, the WCI adopted a methodology for the General Stationary Combustion category that eliminated the use of 40 CFR Part 75 type CEMS unless a unit was already equipped with both a stack gas volumetric flow rate monitor and a CO_2 CEM. WCI also eliminated the use of Part 75 CEMS for municipal solid waste combustion units and established the use of Tier 2 calculation methodologies. The U.S. Department of Energy (DOE) 1605 (b) Voluntary Reporting program offers similar flexibility in its "A-Rated Measurement and Estimation Method" for stationary combustion sources. The DOE approach includes: 1. Use of continuous direct measurement of CO_2 at facilities that have already installed CEMs for CO_2; 2. Use of emission factors based on multiple, regularly repeated, on-site direct measurement of source emissions; and 3. Use of measured source activity data (e.g., amount of MSW processed, steam production.) WM recommends that EPA incorporate similar requirements for municipal waste combustors in the final MMR. As WCI concluded, accurate annual GHG emissions result when using the Tier 2 calculation methodology, including use of actual steam generation or waste throughput data, CO_2 emission factors, heat input to steam output or stack flow rate to steam output ratios, and fuel HHV.

Response: See the response to comment EPA-HQ-OAR-2008-0508-0544.1 excerpt 4.

EPA believes that it is appropriate to require the use of CEMS on the largest MSW combustion sources and any smaller MSW combustion source which already has CO_2 concentration monitors and stack gas volumetric flow rate monitors in place. EPA has, however, clarified that all of the criteria in §98.33(b)(4)(ii) or (iii) must be present to require the use of Tier 4. EPA believes that it is appropriate for MSW combustion units to use ASTM D6866-06a and D7459-08 on a quarterly basis to determine the relative proportions of biogenic and non-biogenic CO_2 emissions from the MSW combusted. Where Tier 2 is used, EPA has provided for MSW combustion units to determine total CO_2 emissions from the amount of steam produced, boiler design, and a default CO_2 emission factor. EPA believes that this is more appropriate than determining site-specific factors during annual testing. Where Tier 4 is used, CO_2 emissions are determined using a CO_2 concentration monitor and a stack gas volumetric flow rate monitor. Biogenic emissions for the MSW combustion unit are then calculated by multiplying the total CO_2 emissions for the year, determined using Tier 2 or 4, by the fraction of biogenic emissions, determined using the ASTM methods.

Commenter Name: Gary Moore
Commenter Affiliation: Pensacola Plant of Ascend Performance Materials LLC
Document Control Number: EPA-HQ-OAR-2008-0508-0366.1
Comment Excerpt Number: 3

Comment: It was assumed that the requirement for process GC analyzers to measure carbon content and molecular weight daily would not be burdensome as they were likely already installed to optimize process operation (see page 16484). Off gas streams that are subject to control requirements are not typically monitored as they are required to be controlled. The addition of process GCs for the analyses required in §98.33(b)(3)(ii) and §98.34(d)(3) would be expensive and invalidates the cost assumption in the Preamble.

Response: EPA has retained the daily sampling requirement for other gaseous fuels, due to process gas variability, but only for facilities with existing equipment in place that is capable of providing the data. Otherwise, weekly sampling is now required. EPA also has limited the Tier 3 requirement to fuels that make up at least ten percent of the annual heat input for a unit with a maximum rated heat input capacity greater than 250 mmBtu/hr.

Commenter Name: Mike Aire
Commenter Affiliation: Newmont Mining Corporation (NMC)
Document Control Number: EPA-HQ-OAR-2008-0508-0378.1
Comment Excerpt Number: 3

Comment: EPA Allow Certified Reporting Systems (GRI, TCR) to Report Emissions EPA should develop a reporting format that is fully compatible with other credible reporting systems such as The Climate Registry so that data can be electronically transferred between databases to save time and money.

Response: See the Preamble, Section II. O., for the response on the relationship of this rule to other programs, and for the response on collection, management, and dissemination of GHG emissions data.

Commenter Name: Allen Kacenjar
Commenter Affiliation: Squire Sanders
Document Control Number: EPA-HQ-OAR-2008-0508-0492.1
Comment Excerpt Number: 2

Comment: EPA was correct to define the parameters of Subpart C so that sources operating only a continuous opacity monitoring system ("COMS") are not obligated to conduct Tier 4 monitoring. As explained in the Preamble, §98.33(b)(5) is intended to "require the use of certified CEMS to quantify CO_2 mass emissions where existing CEMS equipment is installed" which "include a gas monitor of any kind or a flow monitor (or both)." The Proposed Rule expressly defines the term "Continuous Emissions Monitoring System" to mean "the total equipment required to sample, analyze, measure, and provide, by means of readings recorded at least once every 15 minutes, a permanent record of gas concentrations, pollutant emission rates, or gas volumetric flow rates from stationary sources." §98.6. COMS do not monitor gas concentrations or flow rates. Rather, they continuously measure opacity by transmitting a beam of light across the stack to a receiver on the other side. The light is absorbed or deflected by visible particles in the flue gas stream. An opacity reading is derived by measuring how these flue gases attenuate the light beam between transmission and receipt. Thus, COMS are an optical technique designed to simulate the results of a visual opacity reading performed by a human using U.S. EPA Test Method 9. COMS detect only the ability of particles in flue gas streams to refract light and lack the capacity to distinguish pollutant emission rates or gas concentrations of any sort. Similarly, COMS do not measure the volume of gas flowing through the stack because the monitors are not designed to determine quantity of a pollutant being emitted. Thus, they comfortably fall beyond the express definition of CEMS in the Proposed Rule. Distinguishing between CEMS and COMS for purposes of triggering Tier 4 reporting is consistent with the distinct treatment these different monitoring technologies receive in existing Clean Air Act rules. The New Source Performance Standards establish different calibration techniques for CEMS and COMS and contain completely distinct performance specifications. This is necessary because CEMS performance specifications must address issues with sample interfaces, pollutant analyzers, and diluent analyzers that do not exist for COMS. The National Emission Standards for Hazardous Air Pollutants (NESHAPs) for Source Categories also define CEMS and COMS separately. CEMS are systems that can sample, condition, analyze, and record emissions, whereas COMS are simpler systems that can only measure opacity. The NESHAPs also distinguish between the two systems in discussing the timing of monitoring cycles and calibration requirements, and may require installation of one, both, or neither of these monitoring systems. Due to the operational and regulatory differences between CEMS and COMS, EPA's underlying rationale for requiring Tier 4 reporting at facilities that operate CEMS does not apply to facilities that only operate COMS. As noted above, EPA's rationale for requiring facilities with CEMS that do not monitor CO_2 to "upgrade" to CO_2 CEMS is that the "incremental cost" will not be unduly burdensome because they are "already required to install, certify, maintain, and operate CEMS and to perform ongoing QA testing of the existing monitors." 74 Fed. Reg. at 16483. Those assumptions do not hold true to facilities that only operate COMS. Instead of bearing only the "incremental cost" of upgrading existing CEMS equipment, COMS-only facilities would functionally start from the same position as a facility with no continuous monitoring apparatus at all. [Footnote: See Exhibit A in DCN EPA-HQ-OAR-2008-0508-0492.1 for a cost Quotation and Scope of Work prepared by CEMTEK Environmental for Orrville Municipal Utilities. As detailed in that quotation, the up-front cost of installing a single CO_2 CEMS at a facility that already possesses COMS is expected to total approximately $250,000.] Thus, the end result of mandating Tier 4 monitoring at COMS-only facilities would be imposition of the "undue burden" EPA acknowledges it is trying to avoid. To eliminate any remaining ambiguity in the rule, AMP-Ohio requests express confirmation that the Proposed Rule, as written, does not mandate Tier 4 reporting at sources that only operate COMS.

Response: EPA has added language to the final rule clarifying that only sources meeting all of the requirements in §98.33(b)(4)(ii) or (iii) will be required to use Tier 4 methods. Sources operating only COMS, therefore, will not be required to use Tier 4. EPA does not believe that any further language is necessary to address this issue.

Commenter Name: J. Southerland
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2008-0508-0165
Comment Excerpt Number: 17

Comment: For simple combustion of carbon based fuels, stoichiometric calculations should always be acceptable for emissions values. One atom of carbon always will produce one molecule of carbon dioxide. The mass of carbon in any given fuel is usually known very precisely.

Response: See the Preamble, Section II. L., for the response on the general monitoring approach. EPA's Tier 3 approach is based on the fuel carbon content as suggested by the commenter.

Commenter Name: Helen A. Howes
Commenter Affiliation: Exelon Corporation
Document Control Number: EPA-HQ-OAR-2008-0508-0373.1
Comment Excerpt Number: 22

Comment: Exelon supports the monitoring and emissions calculation methodologies proposed for stationary combustion. We feel these requirements are largely consistent with the Acid Rain Program requirements and successfully build on the monitoring and emissions quantification approaches of this program.

Response: EPA appreciates your support and thanks you for your comment.

Commenter Name: Jerry Call
Commenter Affiliation: American Foundry Society (AFS)
Document Control Number: EPA-HQ-OAR-2008-0508-0356.2
Comment Excerpt Number: 9

Comment: AFS agrees with EPA that facilities may quantify CH_4 and N_2O emissions from fuel combustion using default emission factors or as an alternative to consider them de minimis and ignored completely. By EPA's admission, the option of requiring periodic stack testing was too costly for the small improvement in data quality and the emissions from stationary combustion source are relatively low compared to CO_2 emissions.

Response: EPA appreciates the comment, and has retained in the final rule the provision to report CH_4 and N_2O from stationary combustion sources based on fuel-specific emission factors. EPA believes that this approach strikes an appropriate balance between minimizing the burden on reporters and obtaining valuable GHG emission data. EPA has, however, revised the final rule to exempt from reporting CH_4 and N_2O emissions from fuels for which the rule does not provide emission factors, and has deleted the provision allowing the owner or operator of a facility to develop site-specific emission factors for such fuels. EPA believes that this change will reduce the reporting burden on facilities.

Commenter Name: Susan Amodeo Cathey
Commenter Affiliation: Air Liquide USA, LLC
Document Control Number: EPA-HQ-OAR-2008-0508-0464.1
Comment Excerpt Number: 5

Comment: The proposed rule imposes the Tier 4 calculation methodology on sources meeting the conditions specified under §98.33(b)(5)(ii). As worded, it appears any one of the (A), (B), (C), or (D) conditions would result in the Tier 4 method being required. Table C-1 appears to indicate that Tier 4 is required only for Solid Fossil Fuel fired units > 250 mmBTU/hr (meeting other criteria, as well) and that Gaseous Fossil Fuel fired and Liquid Fossil Fuel fired combustion units are required to use no more rigorous than Tier 3 methods. The current language of §98.33(b)(5)(ii) would imply any of the conditions described in §98.33(b)(5)(ii)(A), (B), (C) or (D) trigger the Tier 4 method requirement. EPA should clarify the requirement to employ the Tier 4 calculation method. Resolve the apparent discrepancy between the intent to limit Tier 4 to only Solid Fossil Fuel fired combustion units, per Table C-1 of the Preamble, with the actual imposition of Tier 4 described under §98.33(b)(5)(ii). Specifically, conditions (A), (B), (C), and (D) should be separated by the word "and" - absent that, an implied "or" would force this calculation method on many other combustion units for which it was not intended.

Response: EPA acknowledges the commenter's concerns regarding Tier 4 applicability. EPA has revised §98.33(b)(4)(ii) of the final rule to clarify that all criteria must be met before Tier 4 is required.

Commenter Name: Kerry Kelly
Commenter Affiliation: Waste Management (WM)
Document Control Number: EPA-HQ-OAR-2008-0508-0376.1
Comment Excerpt Number: 5

Comment: As the WCI recognized, the substantial costs to implement Tier 4 methodology are very difficult to justify since the Tier 2 methods provide CO_2 emissions of sufficient accuracy. All of Waste Management's sixteen Wheelabrator MWC facilities have state-of-the-art wet or dry extractive Part 60 CEMs that use O_2 for diluent correction. None of the facilities have stack gas flow monitors, only two have Part 60 certified CO_2 CEMS, and half of the facilities have dry-based CEMS without moisture monitoring. Consequently, for WM and most, if not all, other large MWCs nationally, extensive CEM retrofits would be required to comply with Tier 4 including: installation of stack flow monitors; installation of moisture monitors for dry based systems; installation of CO_2 analyzers and integration into existing CEMs; plant modifications and integration including: installation of stack flow monitor ports, signal and power wiring, wiring tray or conduit and new access platforms (depending on suitable flow monitor location); new CEM data systems for automatic data substitution and reporting; and initial certification of flow monitoring systems and CO_2 analyzers. Based upon cost estimates from our approved CEMS equipment vendors, we estimate WM's costs of installation would range up to $4.5 million, with annual operating costs of a half a million dollars. Further, the purchase, installation, startup and certification process for the new equipment would likely delay reporting of 2010 emissions data collection and subsequent reporting.

Response: EPA's estimates of monitoring costs are averages and may not represent the actual cost in individual circumstances.

Please see the response to comment EPA-HQ-OAR-2008-0508-0544.1 excerpt 4 for additional information related to methodologies for MSW combustion.

EPA believes that it is appropriate to require the use of CEMS on the largest MSW combustion sources and any smaller MSW combustion source which already has CO_2 concentration monitors and stack gas volumetric flow rate monitors in place. EPA has, however, clarified that all of the criteria in §98.33(b)(4)(ii) or (iii) must be present to require the use of Tier 4. The commenter should note that, where all of the monitors necessary for Tier 4 have not been installed and certified by January 1, 2010, emissions may be reported for 2010 using either Tier 2 or Tier 3. Tier 4 must then be used starting January 1, 2011.

Commenter Name: Susan Amodeo Cathey
Commenter Affiliation: Air Liquide USA, LLC
Document Control Number: EPA-HQ-OAR-2008-0508-0464.1
Comment Excerpt Number: 4

Comment: The proposed rule defines the applicability of the alternate calculation method "tiers" based on combustion unit size and availability of data, with a general trend to require more rigorous calculation methods (e.g. increasing from Tier 1 to Tiers 2, 3, and 4) for higher operating capacity units and facilities that currently employ certain process or emission measurements. This push for more rigorous calculation methods is made without regard for the underlying accuracy of the calculation method or the quality and completeness of existing process or emission measurement, or the cost of the necessary measurement equipment or practice. The result is a rule that often requires a costly, laborious measurement/calculation method that does not improve the accuracy or completeness of the emission estimate. In many instances, less rigorous calculation methods (e.g., "lower" Tiers) will yield comparable (or better) accuracy emission estimates, with higher reliability and at lower cost. EPA should clarify the applicability of the alternate combustion emission calculation methods. In particular: 1. Allow use of the Tier 1 method for units of any size (currently restricted to units < 250 mmBTU/hr or less), particularly for standard fuels of commerce such as natural gas, LP gas and fuel oils, where billing-quality consumption data is accurate and readily available and the default HHV and CO_2 emission factors are well known constants (as noted in the Preamble for the proposed rule - natural gas carbon content is always within 1% of the default ratio). 2. Recognize that a source's current practices of occasionally characterizing fuels for HHV or carbon content does not necessarily constitute having data "available" consistent with the compliance expectations of Tiers 2 and 3. Where Tiers 2 or 3 would be required, existing fuel characterization may not be according to the specified analytical methods or at the required frequency. Do not require Tier 2 or 3 where data fully meeting the defined compliance expectation is not currently being obtained.

Response: See the Preamble, Section II. L., on General Monitoring Requirements for the overall rationale for methodologies required under this rule, and the response to comment EPA-HQ-OAR-2008-0508-0909.1 excerpt 4 and EPA-HQ-OAR-2008-0508-0580 excerpt 10 for the rationale for methodologies required under Subpart C.

EPA disagrees with the commenter's suggestion of allowing Tier 1 reporting for all facilities and the claim that more rigorous methods do not improve accuracy. Methodologies that reflect the variability of fuels across units and facilities through sampling and measurement are more accurate than methodologies that do not account for this variability (General Stationary Combustion Technical Support Document, EPA-HQ-OAR-2008-0508-0004). The gains from measurement vary by fuel type (i.e., heterogeneity of carbon content and heat rate is lower in some fuels) and the final rule accounts for this difference by varying the requirements for units, with due consideration of burden and cost.

EPA did not choose to adopt a simplified calculation method approach (e.g., using default emission factors) for all units because the data would be less accurate than under the selected option and would not make use of site-specific data that many facilities already have available and refined calculation approaches that many facilities are already using. EPA has, however, expanded the use of the Tier 2 calculation methodology based on fuel heating value to units of any size in which the only fossil fuels combusted are pipeline quality natural gas, and/or distillate oil, in view of the homogeneous nature of these fuels. EPA believes that the final rule makes it clear that a unit will only be required to use Tier 2 (if it otherwise qualifies for Tier 1) if the owner or operator routinely performs fuel sampling and analysis for the fuel high heat value or routinely receives the results of HHV sampling from the fuel supplier at the minimum frequency specified in §98.34.

Commenter Name: Mike Aire
Commenter Affiliation: Newmont Mining Corporation (NMC)
Document Control Number: EPA-HQ-OAR-2008-0508-0378.1
Comment Excerpt Number: 4

Comment: Newmont requests more details on how a facility boundary is determined.

Response: In response to the comment, the Agency does not believe any additional language is needed to clarify the definition of "facility." The use of the term in this part is addressed in §98.6 of the final rule with a detailed description of its meaning. The explanation provided states that "*Facility* means any physical property, plant, building, structure, source, or stationary equipment located on one or more contiguous or adjacent properties in actual physical contact or separated solely by a public roadway or other public right-of-way and under common ownership or common control, that emits or may emit any greenhouse gas. Operators of military installations may classify such installations as more than a single facility based on distinct and independent functional groupings within contiguous military properties."

Commenter Name: Kerry Kelly
Commenter Affiliation: Waste Management (WM)
Document Control Number: EPA-HQ-OAR-2008-0508-0376.1
Comment Excerpt Number: 2

Comment: EPA's most recent national GHG inventory (Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 - 2007, April 2009) reports WTE facilities emit very small amounts of GHG relative to other electricity producing sources. Municipal waste combustors account for only 0.34 percent of total CO_2 equivalent emissions from all Energy Related Activities (20.8 Tg CO_2e from a total of 6170.3 Tg CO_2e from the entire source category) and only 0.55 percent of total CO_2e emissions from the Combustion Source sector in EPA's proposed reporting rule. Based on WTE's relatively small contribution to GHG emissions in their sector, WM suggests that more flexible and cost effective GHG reporting requirements are appropriate and would result in data of sufficient accuracy and reliability to meet EPA's needs.

Response: The commenter did not make a specific suggestion for revised reporting requirements. EPA believes that it is appropriate to require the use of CEMS on the largest MSW combustion sources and any smaller MSW combustion source which already has CO_2 concentration monitors and stack gas volumetric flow rate monitors in place. EPA has, however, clarified that all of the criteria in §98.33(b)(4)(ii) or (iii) must be present to require the use of Tier 4.

Commenter Name: Stephen E. Woock
Commenter Affiliation: Weyerhaeuser Company
Document Control Number: EPA-HQ-OAR-2008-0508-0451.1
Comment Excerpt Number: 2

Comment: We direct EPA's attention to the unnecessary burden (and counter-productive emergence of a potentially substantial carbon footprint from a new national sampling and testing program) of making frequent direct measurements of carbon content or heat content of fuels for stationary combustion sources when the requisite accuracy can be achieved, as allowed under most GHG reporting systems, by use of activity data, emissions factors and engineering calculations, which EPA outlines in the Tier 1 requirements.

Response: See the Preamble, Section II. L., on General Monitoring Requirements for the overall rationale for the methodologies required under this rule, and the response to comment EPA-HQ-OAR-2008-0508-0909.1 excerpt 4 and EPA-HQ-OAR-2008-0508-0580 excerpt 10 for the rationale for methodologies required under Subpart C.

EPA disagrees with the commenter's suggestion of allowing Tier 1 reporting for all facilities. EPA did not choose to adopt a simplified calculation method approach (e.g., using default emission factors) for all units because the data would be less accurate than under the selected option and would not make use of site-specific data that many facilities already have available and refined calculation approaches that many facilities are already using. Methodologies that reflect the variability of fuels across units and facilities through sampling and measurement are more accurate than methodologies that do not account for this variability. The gains from measurement vary by fuel type (i.e., heterogeneity of carbon content and heat rate is lower in some fuels) and the final rule accounts for this difference by varying the requirements for units, with due consideration of burden and cost.

However, the commenter should note that the mandatory fuel sampling and analysis requirements for Tiers 2 and 3 have also been considerably revised in order to reduce the burden on reporters. §98.34 of the final rule requires that natural gas be sampled semiannually. For fuel oil and coal, a representative sampling is required for each fuel lot, i.e., for each shipment or delivery. For other liquid fuels and biogas, quarterly sampling is required. For other solid fuels, excluding municipal solid waste, weekly composite sampling with monthly analysis is required. For other gaseous fuels, the daily sampling requirement has been retained, but only for facilities with existing equipment in place that is capable of providing the data. Otherwise, weekly sampling is required. The final rule also clarifies that fuel sampling and analysis data provided by the supplier may be used in the emission calculations.

Commenter Name: Randal G. Oswald
Commenter Affiliation: Integrys Energy Group, Inc.
Document Control Number: EPA-HQ-OAR-2008-0508-0569.1
Comment Excerpt Number: 2

Comment: The measurement of distillate oil or natural gas fuel flow meters in Subpart C should include fuel flow meters that measure mass flow. Similarly the calculations methods should include equations for the use of fuel flow meters that measure mass flow. It seems that Subpart C, Tier 3 methodology presumes that the quantity of liquid or gaseous fuel combusted is directly measured as a volume of liquid or gaseous fuel. Fuel flow meters may directly measure volume or mass of fuel combusted. The Tier 3 methodology should be expanded to account for either type of fuel flow meter.

Response: EPA has added language to Subpart C, allowing the use of fuel flow meters that measure mass flow rates for liquid fuels, provided that the fuel density is used to convert the readings to volumetric flow rates. For most fuels, the reporter must determine the density of the fuel using the methods provided, though default densities for certain fuel oils have been provided.

Commenter Name: Michael E. Van Brunt
Commenter Affiliation: Covanta Energy Corporation
Document Control Number: EPA-HQ-OAR-2008-0508-0548.1
Comment Excerpt Number: 2

Comment: The Proposed Rule would require EfW facilities to install new equipment and initiate new operating and testing procedures to implement the Tier 4 methodology as currently written. The increased cost would not increase the quality of data but it would increase the operating cost borne by the owner, often municipalities. The EfW facility is a small source of GHG emissions due to the combustion process but it is a GHG mitigation technology on a lifecycle assessment basis.

Response: Please see the response to comment EPA-HQ-OAR-2008-0508-0544.1 excerpt 4 for a discussion of the requirements for units combusting MSW.

EPA believes that it is appropriate to require the use of CEMS on the largest MSW combustion sources and any smaller MSW combustion source which already has CO_2 concentration monitors and stack gas volumetric flow rate monitors in place. EPA has, however, clarified that all of the criteria in §98.33(b)(4)(ii) or (iii) must be present to require the use of Tier 4.

Commenter Name: Randal G. Oswald
Commenter Affiliation: Integrys Energy Group, Inc.
Document Control Number: EPA-HQ-OAR-2008-0508-0569.1
Comment Excerpt Number: 1

Comment: Subpart C, Tier 4 monitoring methods should include the option to employ 40 CFR part 75 Appendix D and G excepted monitoring methods for distillate oil and natural gas fired combustion units of any size. Under subpart D-Electricity Generation of the proposed rule, Acid Rain Program (ARP) affected units shall continue to monitor and report CO_2 mass emissions in accordance with the monitoring requirements of 40 CFR Part 75. ARP affected units must install CO_2 or O_2 and flow continuous emission monitors (CEMS). However, for certain distillate oil and natural gas ARP affected units, excepted monitoring methods may be used in lieu of CEMS. The excepted method of 40 CFR Part 75 Appendix D and Appendix G yield hourly or daily CO_2 emissions acceptable for the Mandatory Greenhouse Gas Reporting Rule. Electrical Generating Units not affected by the ARP monitor CO_2 emissions under a four tiered system of Subpart C of the proposed rule. Distillate oil and natural gas units may elect to employ Tier 4 monitoring methods. Tier 4 only allows CO_2 or O_2 and flow CEMS which are quality assured in accordance with 40 CFR Part 75 requirements. Not included in the Tier 4 monitoring methods of Subpart C are the excepted monitoring methods found in 40 CFR Part 75. It seems only logical that if the Part 75 excepted monitoring methods are satisfactory for measuring, reporting, and quality assuring CO_2 emissions from ARP affected units, then the Part 75 excepted methods are satisfactory for measuring, reporting, and quality assuring CO_2 from non-ARP affected units.

Response: The commenter should note that EPA has added alternative methods for units that report data to EPA according to Part 75, which allow certain oil- and gas-fired units to use methods from Appendices D and G to Part 75. See §98.33(a)(5) of the final rule.

Commenter Name: Mike Aire
Commenter Affiliation: Newmont Mining Corporation (NMC)
Document Control Number: EPA-HQ-OAR-2008-0508-0378.1
Comment Excerpt Number: 1

Comment: Sample Frequency of Carbon Content "For gaseous fuel combustion, EPA considered calculation methodologies based on an assumption that all gaseous fuels are homogeneous. However, the Agency decided against this approach because the characteristics of certain gaseous fuels can be quite variable, and mixtures of gaseous fuels are often heterogeneous in composition. Therefore, the proposed rule requires daily sampling for all gaseous fuels except for natural gas." Specifically, Newmont requests EPA treat propane as a homogeneous fuel. Newmont uses propane in our Carlin roaster during the winter months. Our propane is stored in two large tanks. Each tank is a homogeneous mixture of propane that does not change day to day. Each tank supplies gas to our roaster for one to two weeks. Once a tank reaches a low level set-point, supply is switched to the other tank. Since the gas in a tank is homogeneous, Newmont recommends sampling frequency be reduced to sampling each tank upon filling rather than daily. The daily carbon content sampling requirement for gaseous fuels seems overly onerous and it is recommended that sampling requirements for these fuels be required monthly, consistent with requirements for other fuels. The Draft Rule requires monthly carbon content sampling for natural gas, solid and liquid fuels. Newmont requests that EPA lower the requirement for sampling non-gaseous fuels to new deliveries rather than monthly in order to pinpoint the onset of fuel parameter variations.

Response: EPA has provided a default emission factor (kg CO_2/mmBtu) and HHV (mmBtu/gallon) in Table C-1 for propane.

Commenter Name: Lorraine Krupa Gershman
Commenter Affiliation: American Chemistry Council (ACC)
Document Control Number: EPA-HQ-OAR-2008-0508-0423.2
Comment Excerpt Number: 47

Comment: EPA has requested comment on integrating fuel supplier requirement for HHVs and carbon content for Tier 1 and Tier 2 methodologies, which was not proposed. ACC recommends that EPA should require that the fuel supplier provide data for measured HHV and carbon content for all fuels in commerce. Requiring the fuel supplier to provide this information instead of the fuel users eliminates unnecessary duplication of analysis of the same fuel by multiple users. For example, one fuel supplier might supply many units within an industrial area, and requiring the fuel supplier to provide the data would reduce the number of required analyses correspondingly. In addition, when making this change, EPA should then alter the requirements in §98.34(c) and (d) such that operators of stationary combustion devices do not need to obtain fuel analytical data when it is required to be provided by the fuel supplier.

Response: The final rule clarifies that fuel sampling and analysis data provided by the supplier may be used in the emission calculations. However, EPA has not required fuel suppliers to provide HHV and carbon content data to facilities, as it is the source's responsibility to determine emissions, and it is the role of private sector transactions to specify the terms of information conveyed with fuel purchases. Fuel suppliers have their own reporting requirements in other subparts.

Commenter Name: Kerry Kelly
Commenter Affiliation: Waste Management (WM)
Document Control Number: EPA-HQ-OAR-2008-0508-0376.1
Comment Excerpt Number: 1

Comment: The MRR proposes to require all municipal waste combustors (MWC) with a maximum rated input capacity of greater than 250 tons per day of MSW to use the Tier 4 calculation methodology. This requirement is problematic as it does not reflect current regulatory requirements nor best management practices for MWCs; will be very costly and onerous for these small GHG emitters; and will not result in commensurate enhancements in reporting accuracy. Further, the GHG emission calculation methodology imposed on MWCs is out of proportion to the sector's relative GHG emissions when compared to other electricity generators. As we note below, other GHG reporting programs allow MWCs to use the Tier 2 calculation methodology. In fact, EPA proposes in the MRR to allow fossil fuel-fired, stationary combustion sources with far greater GHG emissions than MWCs to use the Tier 2 calculation methodology. We urge the Agency to reconsider requiring MWCs to use the Tier 4 methodology and recommend that MWCs use a modified Tier 2 methodology analogous to the Title V program methods used for annual reporting of criteria pollutants and hazardous air pollutants (HAP).

Response: Please see the response to comment EPA-HQ-OAR-2008-0508-0544.1 excerpt 4 for an explanation of the requirements for units that combust MSW.

EPA believes that it is appropriate to require the use of CEMS on the largest MSW combustion sources which already have CO_2 concentration monitors and stack gas volumetric flow rate monitors in place. EPA has, however, clarified that all of the criteria in §98.33(b)(4)(ii) or (iii) must be present to require the use of Tier 4. EPA believes that it is appropriate for MSW combustion units to use ASTM D6866-06a and D7459-08 on a quarterly basis to determine the relative proportions of biogenic and non-biogenic CO_2 emissions from the MSW combusted. Where Tier 2 is used, EPA has provided for MSW combustion units to determine total CO_2 emissions from the amount of steam produced, boiler design, and a default CO_2 emission factor.

EPA believes that this is more appropriate than determining site-specific factors during annual testing. Where Tier 4 is used, CO_2 emissions are determined using a CO_2 concentration monitor and a stack gas volumetric flow rate monitor. Biogenic emissions for the MSW combustion unit are then calculated by multiplying the total CO_2 emissions for the year, determined using Tier 2 or 4, by the fraction of biogenic emissions, determined using the ASTM methods.

Commenter Name: Chris Hornback
Commenter Affiliation: National Association of Clean Water Agencies (NACWA)
Document Control Number: EPA-HQ-OAR-2008-0508-0566.1
Comment Excerpt Number: 12

Comment: NACWA recommends that EPA provide additional flexibility and guidance for using actual emissions data to calculate emissions. Many of the factors included in the proposal could be debated or changed, and NACWA believes that many POTWs may have additional information on their combustion units that could provide for more accurate estimates. For example, a number of POTWs will be conducting tests to determine N_2O emissions associated with the burning of biomass. POTWs should be allowed to use the results from these tests to determine their emissions, rather than using the default heating values and emission factors provided by EPA to calculate emissions.

Response: For simplicity and consistency, EPA will require use of specified default values for CH_4 and N_2O, and the Agency has expanded the number of fuels with default CH_4 and N_2O emission factors.

Commenter Name: Jerry Call
Commenter Affiliation: American Foundry Society (AFS)
Document Control Number: EPA-HQ-OAR-2008-0508-0356.2
Comment Excerpt Number: 7

Comment: In reference to proposed section 98.33(a)(1), EPA should allow use of site specific fuel analysis information that would be more representative of fuels combusted than the default values and may be available less frequently than monthly for both Tier 1 (use of the Table C-1 default values) and Tier 2 (use of monthly analyses) methodologies. Sections 98.33(a)(2) and (3) of the proposed regulation, requires monthly analyses of fuels for Tier 2 and 3 (periodic determination of the carbon content of the fuel use 40 CFR part 98 and direct measurement) methodologies. Pipeline quality natural gas and liquid fuels meeting a purchase specification typically do not vary significantly over time. Accordingly, a single analysis or supplier analysis should be adequate. By allowing these more flexible methodologies, EPA can lower compliance and reporting costs and, therefore, minimize the regulatory burdens associated with this proposed rule.

Response: The mandatory fuel sampling and analysis requirements for Tiers 2 and 3 have been considerably revised. EPA agrees with the commenters that for a homogeneous fuel such as pipeline natural gas, monthly sampling is not necessary. For other fuels such as oil and coal, which are delivered in shipments or lots, requiring monthly sampling may be impractical; new fuel lots or deliveries may not be received on a monthly basis. Therefore, §98.34 has been revised to require that natural gas be sampled semiannually. For fuel oil and coal, a representative sampling sample is required for each fuel lot, i.e., for each shipment or delivery. For other liquid fuels and biogas, quarterly sampling is required. For other solid fuels, excluding municipal solid waste, weekly composite sampling with monthly analysis is required. For other gaseous fuels, the daily sampling requirement has been retained, but only for facilities with existing equipment in place that is capable of providing the data. Otherwise, weekly sampling is required. To simplify the emission calculations in Tiers 2 and 3, arithmetic averaging of HHV and carbon content data is permitted if these data are obtained at least at the minimum frequency specified in §98.34, but less frequently than monthly (see §98.33(a)(2)(ii)). If sampling is more frequent, the reporter must calculate a weighted average according to Equation C-2b. However, regardless of the sampling frequency, the owner or operator must use the results of all available valid fuel analyses in the emissions calculations. EPA believes that these revised requirements provide the flexibility the commenter requested.

Commenter Name: Robert P. Strieter
Commenter Affiliation: The Aluminum Association
Document Control Number: EPA-HQ–OAR-2008-0508-0350.1
Comment Excerpt Number: 2

Comment: Although the Aluminum Association agrees that the GHG reporting rule should include direct emissions from significant combustion sources within a facility, it has some concerns with the approach proposed in the rule. Specifically, the proposed tiered reporting protocol included is overly complex and burdensome. In effect, many facilities with various sized combustion units will have to comply with an array of reporting tiers at the process unit level that are complex and expensive to conduct. The complexity of the additional carbon content measurements and heating value measurements will add recordkeeping burdens and costs that are incommensurate with the small potential increase in GHG emission accuracy that could be obtained. This is especially true for gas and liquid fuels that have relatively constant carbon contents. We propose revising to the proposed rule to require only for tier one reporting of gaseous and liquid fuels, and to allow tier two and three reporting only when the reporting facility desires to conduct the additional reporting tiers as an opt-in effort. The provision for only tier one reporting should apply at the very least to small and medium size facilities. The use of fuel specific emission factors for fuel combustion sources is sufficient to meet the goals and objectives of the reporting protocol and should be incorporated in the proposed rule. Since EPA has already developed and established such a reporting mechanism under the Climate Leaders program that has been successfully used by a collection of industries for most of the past decade, it is reasonable to adopt this proven approach here as well. The Climate Leaders Stationary Source Guidance is available at the following website: http://www.epa.gov/stateply/documents/resources/stationarycombustionguidance.pdf. Accordingly, EPA should incorporate the Climate Leaders stationary combustion source reporting guidance in the mandatory GHG reporting program for three important reasons: (1) it provides a suitable technical means for reporting that is accurate and cost effective; (2) it provides continuity with the industries that have been reporting and will continue to report under the Climate Leaders program, and (3) it is consistent with international reporting requirements.

Response: See the Preamble, Section II. L., for the response on the general monitoring approach.

See the response to comment EPA-HQ-OAR-2008-0508-0464.1 excerpt 4 for information on EPA's approach to methodological tiers.

EPA did not choose to adopt a simplified calculation method approach (e.g., using default emission factors) for all units because the data would be less accurate than under the selected option and would not make use of site-specific data that many facilities already have available and refined calculation approaches that many facilities are already using. However, EPA has significantly expanded the use of Tier 1 and Tier 2 Calculation Methodologies. Most units combusting only the biogenic fuels listed in Table C-1 may use Tier 1. The 250 mmBtu/hr restriction on the use of Tier 2 has been lifted for units in which the only fossil fuels combusted are pipeline quality natural gas and/or distillate oil, in view of the homogeneous nature of these fuels. However, the 250 mmBtu/hr unit size cutoff remains for units that combust other fossil fuels.

Commenter Name: Natasha Meskal
Commenter Affiliation: Ecotek
Document Control Number: EPA-HQ-OAR-2008-0508-0346
Comment Excerpt Number: 1

Comment: We would suggest the following standardized units for fuels: Gaseous: mmscf, Liquid: 1000 gallons, Solid: tons. There are few reasons we are suggesting specific units: Most of the local Districts collect the fuel usage data in the proposed units – consequently I believe that a big number of facilities that will be subject to reporting already have tracking systems set up to track their usage in the mentioned units. If industry (or some of the local governments) consider the consolidated reporting of criteria, toxics and GHG emissions - it will allow for easier data transfer and minimize chances for conversion/data entry errors. And the main reason for suggesting these particular standardized units is the fact that EPA FIRE (most commonly used compilation of default emission factors on national level) tends to offer default emission factors either in proposed units or in lbs/heating value. Recently a lot of work/improvements were done on FIRE. It already contains some GHG default emission factors that I hope, will soon be greatly expanded.

Response: EPA believes that the units of short tons for solid fuel, standard cubic feet for gaseous fuel, and gallons for liquid fuel are appropriate. Different companies and industries use different units, and EPA is unable to standardize across all of them. The units EPA requires are sufficiently common in usage that EPA does not believe that it will be burdensome for facilities which track fuel usage in other units to convert to these units for the purpose of calculating GHG emissions.

Commenter Name: Carl H. Batliner
Commenter Affiliation: AK Steel Corporation
Document Control Number: EPA-HQ-OAR-2008-0508-0337.1
Comment Excerpt Number: 8

Comment: Steel Industry facilities may have several combustion sources having a maximum heat input capacity greater than 250 MMBtu/hr. These sources include coke battery underfiring, slab reheat furnaces, as well as boilers. The sources may be fueled by coke oven gas, blast furnace gas, and or natural gas. Subpart C requires these sources to utilize Tier 4 methodology to calculate GHG emissions based on the heat input rating. However, these sources are not typically equipped with the instrumentation to comply with Tier 4 methodology, and requirements to install such equipment are contrary to statements elsewhere in the rule that new monitoring equipment is not required. Utilizing Tier 1 methodology has always been sufficient for calculating criteria pollutant emissions for emission inventory reporting for combustion sources. AK Steel believes that it should be sufficient for GHG emission reporting too and respectfully requests that EPA consider stipulating Tier 1 methodology regardless of the combustion unit's heat input capacity. The additional cost and burden to implement and operate Tier 4 methodology does not justify the minimal, if any, benefit gained.

Response: EPA has clarified the criteria for use of the Tier 4 methodology in §98.33(b)(4)(ii) of the final rule such that all the conditions specificied must be met for Tier 4 to be required.

EPA disagrees with the commenter's suggestion of allowing Tier 1 reporting for all facilities. See the response to comment EPA-HQ-OAR-2008-0508-0464.1 excerpt 4 for more explanation of EPA's approach to methodological tiers.

EPA, however, has significantly expanded the use of the Tier 2 Calculation Methodology for units that combust only natural gas and/or distillate oil, in view of the homogeneous nature of these fuels. However, the Tier 3 methodology is still required for large 250 mmBtu/hr units that combust residual oil, solid fossil fuel, and other gaseous fuels (including coke oven gas and blast furnace gas).

EPA also has limited the Tier 3 requirement to fuels that make up at least ten percent of the annual heat input for a unit or group of units.

Commenter Name: Carl H. Batliner
Commenter Affiliation: AK Steel Corporation
Document Control Number: EPA-HQ-OAR-2008-0508-0337.1
Comment Excerpt Number: 7

Comment: In the event that EPA decides not to delete the reporting requirement for coke oven gas and blast furnace gas combustion for the Steel Industry, EPA needs to consider that combustion of coke oven gas and blast furnace gas in various sources is a common function. Subpart C requires the reporting of CH_4 and N_2O emissions from all combustion sources using default values for various fuels shown in Table C-3. However, no values are presented for coke oven gas and blast furnace gas. In addition, we are not aware of any reliable emission factors for

CH_4 and N_2O for coke oven gas and blast furnace gas combustion but believe concentrations of these emissions to be insignificant, if present at all, in the exhaust gases. Accordingly, AK Steel requests that EPA delete the requirement to include CH_4 and N_2O emission estimates for coke oven gas and blast furnace gas combustion sources.

Response: EPA acknowledges the concerns of the commenter. Table C-2 has been revised to include CH_4 and N_2O emission factors for more fuels, including blast furnace gas and coke oven gas, as well as generic emission factors covering all fuel types listed in Tables C-1. EPA has also deleted §98.33(c)(4), which allowed facilities burning other fuels to develop site-specific emission factors based on the results of source testing, and revised the rule to require reporting of CH_4 and N_2O emissions only from fuels listed in Table C-2.

Commenter Name: Mark Nordheim
Commenter Affiliation: Western States Petroleum Association
Document Control Number: EPA-HQ-OAR-2008-0508-0228k
Comment Excerpt Number: 3

Comment: The second area I want to talk a little bit about is the use of continuous emission monitors. We've read and reread the sections in the rule and Preamble that relate to Tier 4. And certainly several of us see an inconsistency in the Preamble language and the actual language text. It was kind of interesting, I've worked with the California rule so long I start reading the rules. My peers start reading the Preamble. And we didn't have the same answer because the language in the rule specifically says in Tier 4 anybody over, with a heater and boiler over 250,000,000 BTU/hour design capacity has a continuous emission monitor. For us, because we have in a typical refinery, we will have 50-plus heaters and boilers, some of which have dual stacks. For Chevron, as an example, that would mean 15 continuous emission monitors that would have to be installed, which wouldn't essentially be of any value to us in the construct of the ARB rule or the WCI. We'd have to report those emissions, subtract those from emissions that come from our central fuel systems. And so we'd end up with spending a lot of money on continuous analyzers or continuous stack analyzers. We are continuously measuring flow and would be required to measure our carbon content daily. So we think we can get very accurate numbers. So I don't know what is right or wrong, the Preamble or the rule. But clearly we would go forward on the Preamble characterization of the requirement.

Response: EPA acknowledges the commenter's concerns regarding Tier 4 applicability. EPA has revised §98.33(b)(4)(ii) of the final rule to clarify that all six criteria specified in subparagraphs (A) through (F) must be met before Tier 4 is required.

Commenter Name: Scott Evans
Commenter Affiliation: CleanAir Engineering (Clean Air)
Document Control Number: EPA-HQ-OAR-2008-0508-0696.1
Comment Excerpt Number: 2
Form Letter? Yes

Comment: We encourage EPA to consider the use of Predictive Emission Monitoring Systems (PEMS) for those sources where such systems are approved for use for other purposes or where they make sense. We feel that a properly designed and calibrated PEMS can provide data that is as reliable as a CEMS. We recognize that not all sources are good candidates for PEMS but we do feel that for those that are, PEMS should be allowed. Since EPA has recently promulgated Performance Specification 16, there exists a mechanism for ensuring any installed PEMS continues to meet the highest data quality specifications. We feel PEMS should be included in Tier 4 methodology.

Response: The Agency acknowledges the concerns of the commenters, but has only required the Tier 4 methodology for large solid fuel-fired units and MWC units that already are required to have a gas monitor or a stack gas volumetric flow rate monitor, or both. The Tier 4 methodology is being prescribed to large these units because it is difficul to measure fuel consumption rates. Inclusion of PEMS in Tier 4, as an alternative to CEMS, is inappropriate, because PEMS are not suitable for use on units that combust solid fossil fuel. Rather, PEMS are primarily used to estimate NO_x emissions from gas turbines, and gas-fired boilers. Under the Acid Rain Program, EPA has approved the use of PEMS only for these two applications. The Agency is not opposed to innovative, alternative approaches for estimating CO_2 mass emissions. However, the commenter did not provide any supplementary information explaining how a PEMS could be used to predict CO_2 mass emissions, or why Tier 4 would be the appropriate place for this methodology. In view of this, EPA has not incorporated the commenter's suggested approach into the final rule, but is willing to consider it in a future rulemaking, if the necessary technical details of the method are provided for Agency review.

Commenter Name: Scott Evans
Commenter Affiliation: Clean Air Engineering
Document Control Number: EPA-HQ-OAR-2008-0508-0228e
Comment Excerpt Number: 3

Comment: The last thing that I would like to comment on is some other technologies in terms of measurement. The proposal is silent on predictive emission monitoring systems. As you know, EPA has just come out with a performance specification for PEMS that subjects these software-based monitoring solutions to the same kinds of QA/QC that continuous emission monitors are, which may provide an alternative for some sources. I don't want to say that PEMS are not applicable, I don't believe, to every kind of source. For those that it would be appropriate for, that might provide an alternative to hardware CEMS that may provide data of high quality. And, of course, the other thing I mentioned previously is to allow the use of thermo dynamic modeling to replace or as an alternative, let's say, to direct measurement of coal fuel feed for those choosing to use the calculation approach.

Response: The commenter suggests that PEMS may be a suitable alternative to CEMS that can provide data of high quality. However, PEMS are not suitable for use on units that combust solid fossil fuel. Rather, PEMS are primarily used to estimate NO_x emissions from gas turbines, and gas-fired boilers. The Agency is not opposed to innovative, alternative approaches for estimating CO_2 mass emissions, but the commenter did not provide any supplementary information explaining how a PEMS could be used to predict CO_2 mass emissions. In view of this, EPA has not incorporated the commenter's suggested approach into the final rule, but is willing to consider it in a future rulemaking, if the necessary technical details of the method and a cost analysis are provided for Agency review.

Commenter Name: Scott Evans
Commenter Affiliation: Clean Air Engineering
Document Control Number: EPA-HQ-OAR-2008-0508-0228e
Comment Excerpt Number: 1

Comment: I would like to support EPA's proposed tier structure with regard to monitoring, which puts measurement first, in the highest tier. I'm the one that delivered that paper on air and waste that the previous speaker referred to. In fact, there are large discrepancies between measured and calculated CO_2 emissions despite the protestations of some that the data simply is there that shows there is a discrepancy. And a lot of that comes from uncertainty in the fuel feed rate, which is necessary for doing the calculations. The research that we have done indicated that there could be up to a 20 percent uncertainty in how much coal is going into a large utility boiler. And actually EPA had solicited comment on how to quantify this uncertainty. Unfortunately, the direct answer is somewhat onerous in that, like any instrument, a belt feeder or some other way of feeding the coal into the boiler needs to be calibrated on a regular basis. This becomes progressively problematic because it is in continuous use and is on line. The only opportunity really to do that is during infrequent outages. An alternative to that, to specifically address your comment about uncertainty in fuel feed rate, is to move away from actual direct measurement of fuel feed as many plants are doing right now. They are moving toward a thermo dynamic model to calculate heat input from which you can then determine fuel feed. That has proven to be more accurate than just looking at measuring the coal going into a boiler; and that possibility is not specifically addressed in the proposal and potentially should be.

Response: EPA has required Tier 4 CEMS and stack flow rate monitors for certain solid fuel fired units (units with a gas CEMS or flow rate monitor) because of the difficulty and complexity of monitoring solid fuel consumption noted by the commenter. In Tier 2, EPA has expanded the use of steam production and combustion unit efficiency to calculate CO_2 emissions to other solid fuels in addition to municipal solid waste (MSW). These parameters may also be used to quantify the amount of biomass combusted in a unit. The commenter should note that in Tier 3, solid fuel use is determined based on company records, which could involve calculations such as those suggested by the commenter.

Commenter Name: Lorraine Krupa Gershman
Commenter Affiliation: American Chemistry Council (ACC)
Document Control Number: EPA-HQ-OAR-2008-0508-0423.2
Comment Excerpt Number: 103

Comment: We encourage EPA to be more flexible as it relates to the applicability to the alternate combustion emission calculation methods. In particular: (1) Allow use of the Tier 1 method for units of any size (currently restricted to units < 250 mm BTU/hr or less), particularly for standard fuels of commerce such as natural gas, LP gas and fuel oils, where billing-quality consumption data is accurate and readily available and the default HHV and CO_2 emission factors are well known constants (as noted in the Preamble for the proposed rule – natural gas carbon content is always within 1% of the default ratio). (2) Recognize that a source's current practices of occasionally characterizing fuels for HHV or carbon content does not necessarily constitute having data ³available´ consistent with the compliance expectations of Tiers 2 and 3. Where Tiers 2 or 3 would be required, existing fuel characterization may not be according to the specified analytical methods or at the required frequency. Do not require Tier 2 or 3 where data fully meeting the defined compliance expectation is not currently being obtained. (3) Do not require the use of the Tier 4 method where alternative fuel consumption data is available. Allow optional use of the Tier 4 method where, at the source's discretion. This may be a suitable calculation method where a source uses multiple fuels and/or non-commercial fuels or where existing CEMS systems include CO_2 measurement or can be modified at lower cost than alternative fuel consumption and/or characterization devices/practices. In any case, let the regulated source determine which method is most cost effective for their particular situation.

Response: See the Preamble, Section II. L., for the response on the general monitoring approach.

See the response to comment EPA-HQ-OAR-2008-0508-0464.1 excerpt 4 for an explanation of the approach to methodological tiers.

EPA disagrees with the commenter's suggestion of allowing Tier 1 reporting for all facilities. EPA did not choose to adopt a simplified calculation method approach (e.g., using default emission factors) because the data would be less accurate than under the selected option and would not make use of site-specific data that many facilities already have available and refined calculation approaches that many facilities are already using. EPA has, however, expanded the use of the Tier 2 calculation methodology based on fuel heating value to units of any size in which the only fossil fuels combusted are pipeline quality natural gas, and/or distillate oil, in view of the homogeneous nature of these fuels. EPA believes that the final rule makes it clear that a unit will only be required to use Tier 2 (if it otherwise qualifies for Tier 1) if the owner or operator routinely performs fuel sampling and analysis for the fuel high heat value or routinely receives the results of HHV sampling from the fuel supplier at the minimum frequency specified in §98.34.

The Tier 4 CEMS requirement is limited to larger solid fossil fuel units with an existing pollutant CEMS or volumetric flow rate monitor. EPA is requiring the use of CEMS due to the complexity of monitoring solid fuel consumption and the heterogeneous nature of the solid fuels. Many of these fossil fuel-fired units with a pollutant CEMS have an existing diluent monitor (O_2 or CO_2) that can be used to determine CO_2 emissions.

Commenter Name: Lorraine Krupa Gershman
Commenter Affiliation: American Chemistry Council (ACC)
Document Control Number: EPA-HQ-OAR-2008-0508-0423.2
Comment Excerpt Number: 56

Comment: EPA has requested comment on the use of more technology-specific CH_4 and N_2O emission factors that could be applied in unit-level calculations for §98.33(c). ACC recommends that EPA eliminate CH_4 and N_2O calculations entirely due to their negligible impact on the total greenhouse gas inventory and on a facility's emissions. In §98.33(c), according to the formulae provided, less than 0.00001 percent of the greenhouse gas emissions would be CH_4 or N_2O. Therefore, EPA should not require calculation and reporting of these emissions because their contribution to the total is insignificant.

Response: Please see the response to comment EPA-HQ-OAR-2008-0508-0561.1 excerpt 2 for further explanation of EPA's approach to reporting of CH_4 and N_2O from stationary combustion sources. EPA acknowledges the concerns of the commenter. However, EPA has decided to retain in the final rule the requirement to report CH_4 and N_2O from stationary combustion sources. EPA believes that the use of fuel-specific emission factors for these pollutants strikes an appropriate balance between minimizing the burden on reporters and obtaining valuable GHG emission data. EPA has, however, revised the final rule to exclude CH_4 and N_2O emissions from fuels for which the rule does not provide emission factors, and has deleted the provision allowing the owner or operator of a facility to develop site-specific emission factors for such fuels. EPA believes that this change will reduce the reporting burden on facilities.

Commenter Name: Lorraine Krupa Gershman
Commenter Affiliation: American Chemistry Council (ACC)
Document Control Number: EPA-HQ-OAR-2008-0508-0423.2
Comment Excerpt Number: 54

Comment: Section 98.33(b)(5)(ii)(E) does not specify that the CEMS installed must be a CEMS for monitoring CO_2. ACC believes that EPA meant a CO_2 analyzer, and should specify accordingly to eliminate any uncertainty. If EPA meant any CEMS monitoring device regardless of the CEMS ability to monitor CO_2 without additional equipment modification and possibly equipment purchase, then we recommend that EPA change the requirement to apply to existing CO_2 CEMS only. Requiring the added capability to monitor for other constituents is unnecessarily costly and not necessary for ensuring an appropriate level of accuracy for purposes of compiling an inventory.

Response: See the response to comment EPA-HQ-OAR-2008-0508-0455.1 excerpt 7 and the response to comment EPA-HQ-OAR-2008-0508-0580 excerpt 10 for EPA's rationale and approach to the use of CEMS.

EPA disagrees with suggestions that Tier 4 should only be required if the installed CEMS include a CO_2 monitor. The incremental cost of adding a diluent gas (CO_2 or O_2) monitor or a flow monitor, or both, to meet Tier 4 monitoring requirements would likely not be unduly burdensome for a large unit that combusts solid fossil fuels or MSW, operates frequently, and is already required to install, certify, maintain, and operate CEMS and to perform ongoing QA testing of the existing monitors.

Commenter Name: Allen Kacenjar
Commenter Affiliation: Squire Sanders
Document Control Number: EPA-HQ-OAR-2008-0508-0492.1
Comment Excerpt Number: 1

Comment: Sources should only be obligated to conduct Tier 4 monitoring when actual CO_2 CEMS are already in place. The Proposed Rule's requirement to install CO_2 CEMS at sources with other CEMS is founded on the premise that the "incremental cost" of upgrading "would likely not be unduly burdensome for a large unit that combusts solid fossil fuels or MSW, operates frequently, and is already required to install, certify, maintain, and operate CEMS and to perform ongoing QA testing of the existing monitors." 74 Fed. Reg. at 16483. In all scenarios except where CO_2 CEMS are already in place, actual costs will be more burdensome than the Proposed Rule assumes. One primary reason is that EPA's capital cost estimates are based on "annualized costs over a 15-year timeframe." EPA-HQOAR-2008-0508-0002 at p. 4 - 22. While CO_2 CEMS may operate for 15 years, the real world cash-flow impact of such capital improvements cannot be similarly deferred. Rather, contractors require payment in full no later than the date of installation. Given the challenging economic climate and existing budget constraints, payment of lump-sum capital costs (even assuming the actual amount of those costs matches EPA's estimates) will often create a significant burden. That burden will fall most heavily on SBREFA small entities that must install CO_2 CEMS. [Footnote: The Regulatory Flexibility Act, 5 U.S.C. §§601 - 612, as strengthened in 1996 by the Small Business Regulatory Enforcement Fairness Act ("SBREFA"), was enacted to require proper agency consideration of measures to protect small entities from harm due to agency regulation. The Small Business Administration's related regulations provide that an electric utility is "small if, including its affiliates, it is primarily engaged in the generation, transmission, and/or distribution of electric energy for sale and its total electric output for the preceding fiscal year did not exceed 4 million megawatt hours." 13 C.F.R. §121.201 at fn. 1. AMP-Ohio's generating members (and many similar small municipal utilities nationwide) qualify as small entities but were apparently not considered in EPA's "screening assessment." See 74 Fed. Reg. at 16600. Assessing whether additional costs impose an "undue" burden also requires assessment of the relative benefits expected from such expenditures. The Tier 4 approach appears to provide, at most, very marginal benefit over Tier 3 reporting. As acknowledged in the Preamble, "for combustion sources, the emission rate of CO_2 is directly proportional to the carbon content of the fuel, and virtually all of the carbon is oxidized to CO_2." 74 Fed. Reg. at 16480. Since Tier 3 requires careful monitoring of fuel carbon content and "virtually all" of the measured carbon becomes CO_2, this methodology is more than accurate enough to achieve Congress' expressed goal: the collection of sufficient information to guide future legislative and regulatory efforts. 74 Fed. Reg. at 16456. Indeed, the only expected difference between the Tier 3 and Tier 4 protocols is that Tier 3 reporting may modestly overestimate CO_2 emissions where incomplete combustion results in low-level CO emissions. While that potential for the minor overestimation of CO_2 emissions may create adequate incentive for some sources to voluntarily install CO_2 CEMS (particularly if a cap-and-trade system is created), it does not justify the mandatory imposition of

up-front capital costs. It would be significant overkill to require sources to track down such minute carbon overestimates when the rule claims to cover only 85% of national GHG emissions and exempts all sources under 25,000 metric tons per year. Accordingly, we request that EPA limit mandatory Tier 4 reporting to only units that already have functioning CO_2 CEMS.
Response: See the response to comment EPA-HQ-OAR-2008-0508-0455.1 excerpt 7 and the response to comment EPA-HQ-OAR-2008-0508-0580 excerpt 10 for EPA's rationale and approach to the use of CEMS.

The applicability of Tier 4 has been clarified such that only units that meet all six criteria in §98.33 (b)(4)(ii)(A) through (F) must use CEMS, including the criterion that the "unit has installed CEMS that are required either by an applicable Federal or State regulation or the unit's operating permit." In some cases this requirement may require a unit to install a diluent gas (CO_2 or O_2) and a stack gas volumetric flow rate monitor. The incremental cost of adding a diluent gas monitor or a flow monitor, or both, to meet Tier 4 monitoring requirements would likely not be unduly burdensome for a large unit that combusts solid fossil fuels or MSW, operates frequently, and is already required to install, certify, maintain, and operate CEMS and to perform ongoing QA testing of the existing monitors.

Commenter Name: Kathy G. Beckett
Commenter Affiliation: West Virginia Chamber of Commerce
Document Control Number: EPA-HQ-OAR-2008-0508-0956.1
Comment Excerpt Number: 20

Comment: EPA proposes that all ARP units, and "other units monitoring heat input year round under §75.10(c)" and reporting heat input under §75.64, use Part 75 heat input data (in mmBtu) and a fuel-specific emission factor from Table C-3 to report CH_4 and N_2O. Proposed §98.33(c). For all other units, EPA proposes use of (1) measured HHV, if measured or provided at least monthly, and (2) if not measured monthly, the default HHV specified in Table C-1. Proposed 98.33(c). The Chamber has concerns regarding use of missing data procedures and bias adjustment factors for CH_4 and N_2O. As a result, we request that the same alternative be provided for missing volumetric flow data and Appendix D fuel flow data. It would not necessarily agree to use of bias-adjusted volumetric flow data to calculate heat input, and mass emission of CH_4 and N_2O, in a future program regulating GHG.

Response: See the Preamble, Section III. C., for EPA's response on missing data.

EPA acknowledges the commenter's concerns, but believes that it is appropriate to use the heat input data reported under Part 75 for the purposes of calculating CH_4 and N_2O emissions from Part 75 units. As the commenter points out, this data is already quality-assured and reported to EPA. EPA believes that use of the Part 75 missing data procedures for stack gas flow rate and fuel flow rate will not significantly bias the CH_4 and N_2O emissions estimates. The percent monitor data availability (PMA) for Part 75 flow monitors is, on average, very high (> 95 percent). The small amount of substitute data used by Part 75 units has little effect on the emissions data. The only time that a significant bias may be introduced in the reported stack gas flow rates is when the PMA drops below 80 percent and the maximum potential flow rate must be reported. This is a very rare occurrence. Fuel flow meters are also very reliable and seldom experience missing data incidents. The missing data routines for fuel flow rate are much less conservative than the CEMS routines. Substitute fuel flow rates are very similar to actual fuel flow rates. In view of these considerations, EPA is not revising Part 75 reporting requirements, and for simplicity and cost reasons, EPA is keeping the GHG monitoring requirements consistent with current monitoring requirements.

Commenter Name: Craig S. Campbell
Commenter Affiliation: Lafarge North America
Document Control Number: EPA-HQ-OAR-2008-0508-0674.1
Comment Excerpt Number: 14

Comment: In the definition section (40 CFR §98.6) of the proposed rule EPA defines "Municipal solid waste" ("MSW") to mean "solid phase household, commercial/retail, and/or institutional waste, such as, but not limited to, yard waste and refuse." This is a very broad definition that may be read to include a number of common mixed waste streams which are used as alternative fuels by the cement industry. Commercially generated scrap paper/plastics would be one example. This broad definition, coupled with some of the proposed GHG measurement/calculation methodologies included elsewhere in the proposed rule for MSW (apparently written with MSW incinerators in mind), presents a number of concerns for how cement kiln operators are to handle these calculations. In some cases the proposed measurement/calculation methodologies would be inappropriate and/or entirely unworkable for a cement kiln. For example, EPA is proposing a separate "MSW" calculation method for an emission unit's biogenic emissions. The facility would be required to use ASTM methods listed in the rule to sample and analyze the CO_2 in the flue gas once each quarter, in order to determine the relative percentages of fossil fuel-based carbon (e.g., petroleum-based plastics) and biomass carbon (e.g., newsprint) in the emissions when MSW is combusted in the unit. More specifically: Sources that combust MSW under the proposed rule are required to follow 40 CFR §98.33(e)(3) which states "For a unit that combusts MSW, the owner or operator shall use, for each quarter, ASTM Methods D 6866-06a and D 7459-08, as described in 40 CFR §98.34(f), to determine the relative proportions of biogenic and non-biogenic CO_2 emissions when MSW is combusted." Further to this, under 40 CFR §98.34(f) gas samples shall be taken "during normal unit operating conditions while MSW is the only fuel being combusted, for at least 24 consecutive hours or for as long as necessary to obtain a sample large enough to meet the specifications of ASTM D6866-06a." This aspect of the proposed rule is entirely unworkable for cement kilns using any mixed-waste alternative fuels meeting the proposed rule definition of MSW. Cement kilns typically use mixed-waste alternative fuels at some fuel-replacement percentage (usually much less than 100%) along with traditional fossil fuels. In most cases a cement kiln would not be capable – and often cases not legally permitted - to operate using these "MSW" fuels as the "only fuel being combusted." Lafarge believes it is imperative for EPA to allow a workable (e.g., different) approach for the biogenic emissions determination from cement kilns. It is recommended that cement kilns be allowed to use the Tier 1 method for calculating biogenic emissions, in addition to having the option of using the above mentioned ASTM Methods D 6866-06a and D 7459-08. The Tier 1 method essentially requires fuel mass consumption data along with default biogenic-fuel emission factors for calculating the biogenic emissions. In the alternative, EPA could make an appropriate change to the definition of "MSW" as used in the proposed rule. Assuming EPA's actual intent is to exclude use of the Tier 1 method when MSW is being combusted by dedicated MSW facilities (e.g., municipal waste incinerators processing more-traditional municipal refuse steams), it may be possible to revise the MSW definition such that mixed wastes used as fuels at cement kilns are not captured within the greenhouse gas reporting rule's MSW definition.

Response: EPA has revised §98.33 to allow units which combust MSW and do not produce steam to use Tier 1 to calculate the total CO_2 emissions from MSW combustion. Default emission factors for MSW are provided in Table C-1. Regarding the biogenic CO_2 emissions, EPA disagrees with the commenter that ASTM Methods D 6866-06a and D 7459-08 are unworkable for a cement kiln. The commenter has correctly noted that the proposed rule would have required MSW to be the only fuel combusted when the methods are used. However, the final rule has corrected this and simply states that the ASTM methods are to be used "when MSW is combusted in the unit." These final rule provisions should address the commenter's concerns.

Commenter Name: Marcelle Shoop
Commenter Affiliation: Rio Tinto Services, Inc.
Document Control Number: EPA-HQ-OAR-2008-0508-0636.1
Comment Excerpt Number: 24

Comment: EPA rejected an option of requiring periodic stack testing to derive site-specific emission factors for CH_4 and N_2O because it was too costly for the small improvement in data quality that it might achieve. (74 Fed. Reg. at 16485) Rio Tinto supports this decision. We agree that stack testing for CH_4 and N_2O emissions would not provide enough additional accuracy or benefit to justify the additional cost and effort since these emissions from combustion are so low.

Response: EPA appreciates the supportive feedback, and has maintained these specifications in the final rule. EPA has revised the rule that only CH_4 and N_2O emissions from those fuels listed in Table C-2 of Subpart C are required to be reported.

Commenter Name: Juanita M. Bursley
Commenter Affiliation: GrafTech International Holdings Inc. Company (GrafTech)
Document Control Number: EPA-HQ-OAR-2008-0508-0686.1
Comment Excerpt Number: 24

Comment: If a facility opts to combine all its combustion units that are supplied by a common gaseous or liquid fossil fuel supply piping configuration, which is equipped with a calibrated fuel flow meter, for the purpose of simplifying its emissions calculations, GrafTech understands the facility can do this regardless of the total number of units or regardless of the total maximum rated heat input capacity of the individual units or of the entire group. GrafTech agrees this is an acceptable option. However, since EPA is not restricting the total maximum rated heat input capacity of the combined units, GrafTech believes that the facility should not be required to use the Tier 3 method to calculate CO_2 emissions for any combustion unit > 250 mmBtu/hr. and that this requirement should also not apply to these aggregated combustion units, where any one or more of the units, or the total group of units exceeds this maximum rated heat input capacity. This would potentially negate much of the main reason for aggregating multiple units, which is to simplify the GHG emission calculations, if the facility would now have to use the more complex calculation method for the entire group, requiring either daily or monthly measurements and calculations. A fact to which EPA readily admits in the Preamble, commercially-available gaseous and liquid fuels are typically homogenous so there should be an insignificant variability in the carbon content. That fact coupled with the expected accuracy of the typical supplier billing meter on common fuel supply piping, indicates there would be no significant benefit to requiring the more onerous Tier 3 calculation method to estimate GHG emissions for an aggregated group of units even if the total (or any of the individual unit) maximum heat input capacity exceeds 250 mmBTU/hr. On page 16484 of the Preamble under the discussion of Tier 1, EPA states it "considered" allowing the use of default emission factors, default HHVs and company records to quantity annual fuel consumption for all stationary combustion units, regardless of size or the type of fuel combusted, but "decided to limit the use of this type of calculation methodology to smaller combustion units". However, EPA provides absolutely no justification for this decision, which unnecessarily complicates the emissions estimation procedures. Given the additional burden on reporting facilities, and the arguments provided above, GrafTech requests that EPA allow this simplified and generally accepted Tier 1 estimation procedure in the final rule for all stationary combustion units regardless of size or the type of fuel combusted, at a minimum to quantify annual consumption for commercially-available gaseous and liquid fuels that have established default emission factors and HHVs.

Response: See the Preamble, Section II. L., on General Monitoring Requirements for the overall rationale for methodologies required under this rule, and the response to comment EPA-HQ-OAR-2008-0508-0909.1 excerpt 4 and EPA-HQ-OAR-2008-0508-0580 excerpt 10 for the rationale for methodologies required under Subpart C.

EPA disagrees with the commenter's suggestion of allowing Tier 1 reporting for all fuels and units of any size. EPA did not choose to adopt a simplified calculation method approach (e.g., using default emission factors) because the data would be less accurate than under the selected option and would not make use of site-specific data that many facilities already have available and refined calculation approaches that many facilities are already using.

However, the 250 mmBtu/hr restriction on the use of Tier 2 has been lifted for units in which the only fossil fuels combusted are natural gas and/or distillate oil, in view of the homogeneous nature of these fuels. This is consistent with the common pipe reporting provisions, which allow oil- or gas-fired units sharing a common supply pipe to report jointly using the tier required based on the maximum rated heat input capacity of the largest unit served by the common pipe configuration.

The commenter should also note that the cumulative 250 mmBtu/hr heat input capacity limit on the aggregation of units into a group has been dropped. Rather, the 250 mmBtu/hr restriction applies only to the individual units in the group. Therefore, for reporting purposes, individual units with maximum rated heat input capacities of 250 mmBtu/hr or less may be aggregated without limit into a single group, provided that the Tier 4 methodology is not required for any of the units, and all units in the group use the same tier for any common fuel(s) that they combust.

Commenter Name: See Table 3
Commenter Affiliation:
Document Control Number: EPA-HQ-OAR-2008-0508-0433.2
Comment Excerpt Number: 24

Comment: For the purposes of this rule for most CO_2 and other GHG sources, including catalytic cracking units, fluid coking units, and other refinery combustion and process units, engineering calculations are rejected as being less accurate than are CEMS data. While this may appear true on its face, frequently such calculations can provide comparable or more accurate data than CEMS data, if adequate process information, data on carbon content of materials, and mass of materials processed or combusted are available. Such calculations can often exceed a ± 5% accuracy, while the CEMS monitors specified in the proposed rule are allowed to have data errors as large as ± 20% of the true value for pollutant monitors (40 CFR 60, Appendix B, Performance Specification 2) and ± 1% absolute O_2 or CO_2 concentration (40 CFR 60, Appendix B, Performance Specification 3) during annual compliance certification testing. Furthermore, when the flow monitoring required to report mass emission rates for pollutants is included, the allowable accuracy of the monitoring system is ± 20% of the mean value of the relative accuracy test audit results (40 CFR 60, Appendix B, Performance Specification 6). These accuracy values far exceed those of many engineering calculations. Usually, even the EPA's default high heat values and CO_2 emission factors are likely to be more accurate than ± 20% of the true value. Therefore, little if any value may be expected by requiring the installation of CEMs. NPRA requests that EPA reconsider allowing the use of engineering calculations for calculation of CO_2 emission rates for most refinery sources, including the catalytic cracking units and fluid coking units in refineries.

Response: See the Preamble, Section II. L., for the response on the general monitoring approach.

See the response to comments on Subpart Y regarding refinery process unit monitoring. Refinery process heaters and boilers are not required to install CEMS under the general stationary combustion requirements in Subpart C.

Commenter Name: Marcelle Shoop
Commenter Affiliation: Rio Tinto Services, Inc.
Document Control Number: EPA-HQ-OAR-2008-0508-0636.1
Comment Excerpt Number: 23

Comment: Two of the proposed reporting methodologies for stationary source combustion devices, Tiers 2 and 3 as provided for in 40 CFR 98.33, employ calculations based on the mass of solid fuel (coal) consumed and the sampled mass fraction of the carbon composition of the coal. The carbon content of the coal is based on sampling and analyses of solid fuel (coal) from weekly composite sampling analyzed monthly. 40 CFR 98.34(c) - (d), 74 Fed.Reg.16636. As discussed above, Rio Tinto urges EPA to allow the stationary combustion source to rely on: 1. Supplier information (commercial records such as coal deliveries or invoices) for volume measurements; 2. Default carbon content or HHV default factors; 3. Carbon content or HHV data provided to the source by the coal-fuel supplier. We request EPA to make the rules more dear and explicit that supplier information can be used by industrial combustion sources. The methodologies in proposed 40 CFR 98.33 and the monitoring and QA/QC provisions of 40 CFR 98.34 indicate that the reporter may rely on company records for fuel consumption, but the rules are not entirely dear whether the reporter may rely on commercial records (coal deliveries, invoices) or must undertake additional measurement activities to determine and record consumption. Most important is the need for the combustion source to be able to rely on supplier information for the carbon content or HHV, or alternatively to be able to utilize a carbon default or HHV default factor. Most industrial combustion sources do not have appropriate equipment, facilities or expertise to conduct weekly or monthly sampling of the coal in accordance with the applicable standards. The proposed rule would require coal combustion sources to use ASTM methods to collect representative samples of the fuel bunkered or consumed. See Proposed 40 CFR 98.34(c). Obtaining a representative sample from a coal pile can be difficult and expensive for a coal user. Conversely, many coal suppliers have necessary sampling equipment and expertise to collect representative samples in accordance with applicable ASTM standards. Where they do not, the default factors should be acceptable. Currently, our facility with the coal combustion source receives quarterly carbon content information from the supplier and we utilize this information for making our estimates of CO_2 emissions from the industrial combustion source. Requiring both the combustion source and the supplier (per Subpart KK) to conduct sampling and analyses would be duplicative, inefficient and expensive. Moreover, given the large number of combustion facilities relative to suppliers, there is a potential concern whether there would be sufficient laboratory capacity to analyze samples for carbon content or HHV for all of these combustion facilities in addition to the coal suppliers. Being both a user and a Supplier of coal, Rio Tinto recognizes the need and importance of carefully coordinating the fuel supplier requirements with the requirements applicable to combustion sources to make it dear that combustion sources may use data provided by fuel suppliers.

Response: See the Preamble, Section II. L., for the response on the general monitoring approach.

EPA did not choose to adopt a simplified calculation method approach (e.g., using default emission factors) for all units because the data would be less accurate than under the selected option and would not make use of site-specific data that many facilities already have available and refined calculation approaches that many facilities are already using. However, the commenter should note that in Tiers 2 and 3 the volume of solid fuel combusted is determined using company records, which could include fuel billing records. EPA has revised the sampling requirements for coal so that a representative sample is required for each fuel lot, i.e., for each shipment or delivery. The final rule clarifies that fuel sampling and analysis data provided by the supplier may be used in the emission calculations. EPA notes that Subpart KK Suppliers of Coal is not being included in this rule at this time.

Commenter Name: Juanita M. Bursley
Commenter Affiliation: GrafTech International Holdings Inc. Company (GrafTech)
Document Control Number: EPA-HQ-OAR-2008-0508-0686.1
Comment Excerpt Number: 22

Comment: GrafTech's understanding from §98.33(b)(4) is that the Tier 3 calculation method "may be used" (i.e., at the facility's discretion) for a unit of any size and for any type of fuel, except when Tier 4 is required by the rule. However, this is confused by the apparent indication in Table C-1 and discussions in the Preamble that Tier 3 is "required" for gaseous and liquid fossil fuel use when the combustion unit size exceeds 250 mmBtu/hr. GrafTech wanted to bring this apparent discrepancy to EPA's attention, and express our opinion that use of the Tier 1 and Tier 2 methods should be allowed by EPA for estimating GHGs from combustion of gaseous and liquid fossil fuels available from commercial sources, regardless of the size of the combustion unit(s). We are not familiar with gaseous and liquid fuels that may be obtained from private wells, so are not offering an opinion as to whether emissions from those fuel sources warrant use of the more complex Tier 3 calculation method.

Response: In response to comments, EPA has substantially revised §98.33(b), describing which tier a reporter is to use. EPA has decided to allow the use of Tier 2 methods for units of any size in which the only fossil fuels combusted are pipeline quality natural gas and/or distillate fuel oil. Specific provisions in the final rule clarify when Tier 3 methods are required.

Commenter Name: Marcelle Shoop
Commenter Affiliation: Rio Tinto Services, Inc.
Document Control Number: EPA-HQ-OAR-2008-0508-0636.1
Comment Excerpt Number: 22

Comment: The differences between the proposed emissions calculation methodologies for stationary combustion source rules for natural gas and those for natural gas local distribution companies (LDCs) are not rational and should be aligned. We specifically request that the Tier 2 or Tier 3 calculation methodologies in 40 CFR §98.33 be modified to comport with the calculation methodologies for natural gas suppliers in 40 CFR §98.403, allowing the combustion source, at its option, to calculate emissions either using either default factors or supplier data if available. For stationary sources that combust natural gas, the Tier 2 methodology under Subpart C requires high heat values (HHV) to be determined on a monthly basis using "the applicable fuel sampling and analysis methods incorporated by reference in §98.7." §98.34(c), 74 Fed. Reg. at 16636. The Tier 3 methodology for such facilities would require carbon content and molecular weight to be measured on a monthly basis, using "an applicable method listed in §98.7." §98.34(d)(3). It appears that applicable measurement methods for natural gas would be those listed in the provisions for natural gas suppliers, specifically 40 CFR §98.404(d), 18 e.g., American Gas Association or ASTM. In contrast, the proposed rule does not require natural gas suppliers to measure high heat values or carbon content at all. Rather, Subpart NN authorizes natural gas local distribution companies (LDCs) the option of reporting CO_2e emissions using one of two calculation methodologies, neither of which mandates monthly sampling. See §98.403, 74, Fed. Reg. at 16720. The calculation methodologies rely on the default high heating value or CO_2 emission factors provided in either Table NN-1 or NN-2, as applicable. An LDC also has the option of relying on reporter-specific higher heating values or CO_2 emission factors developed using methods outlined in §98.404(d), which we reference above." In the Preamble, EPA explains that: We considered but do not propose an option in which LDCs and natural gas processing plants would be required to sample and analyze natural gas and NGLs periodically to determine the carbon content. Given the close correlation between carbon content and BTU value of natural gas and NGLs, and the availability of BTU information on these products, EPA believes that periodic sampling and analysis would impose a cost on facilities but would not result in improved accuracy of reported emissions values. 74 Fed. Reg. at 16577. Many stationary combustion sources subject to the Tier 2 or 3 Methodology under Subpart C do not have appropriate equipment, facilities or expertise to conduct monthly sampling of natural gas supplied to the facility. The reason EPA articulated in the Preamble (noted above) for not requiring LDCs to undertake periodic sampling-that the additional costs would not result in improved accuracy of reported emissions values -- appears to be equally applicable for the Tier 2 or 3 methodology for combustion sources (or their suppliers) and monthly sampling should not be required. In some cases, supplier information may be available. We read the proposed rule (§§98.33 and .34) to allow a reporting entity to rely on company records in making the calculations, including information provided by fuel suppliers, on which to base the high heat value or fuel carbon content measurement. However, we request that EPA specifically clarify that stationary combustion sources may rely on high heat value or carbon content data provided by natural gas suppliers or LDCs[20] in utilizing Tier 2 or 3 methodologies. [Footnote: [20] For example, two companies that deliver natural gas to Rio Tinto entities, Kern River Gas Transmission Company and Questar Gas Company, provide online access to their natural gas quality databases: http://services.kemrivergas.com/portallDesktop.aspx and http://www.guestargas.com/ServicesBuslTemnicallnfo.php. In summary, stationary combustion sources should be able to calculate their CO_2 emissions from natural gas combustion using the applicable Tier 2 or 3 Methodologies based on either of the following options: (1) the default values provided in Tables NN-1 and NN-2 for natural gas suppliers; or (2) high heat value or carbon content information as provided by the natural gas supplier or LDC (for example when the LDC chooses to undertake reporter-specific analyses per 40 CFR §98.403-.404); or (3) high heat value or carbon content information as measured by the combustion facility. The comments made in this section related to natural gas apply equally to propane. Some of our facilities use propane as a backup fuel in case natural gas supplies are interrupted for any reason. Propane used for these backup purposes is not used on a regular basis but is stored for potentially long periods. Under these circumstances, it would be impracticable to measure the HHV, carbon content, and/or molecular weight of this fuel, further supporting our recommendation to allow the use of default values or vender supplied data (if available) to calculate emissions from these fuels.

Response: The commenter should note that the final rule allows units of any size in which the only fossil fuels combusted are natural gas and/or distillate oil to use Tier 2. EPA agrees with the commenter that for a homogeneous fuel such as pipeline natural gas, monthly sampling is not necessary. Therefore, §98.34 has been revised to require that natural gas be sampled semiannually. Furthermore, the final rule clarifies that fuel sampling and analysis data provided by the supplier may be used in the emission calculations.

EPA expects that most units combusting propane will have maximum rated heat input capacities less than 250 mmBtu/hr, and will thus be allowed to use Tier 1 or Tier 2. Tier 1 does not require any fuel sampling or analysis. Tier 2 will only be required if the owner or operator of the unit already performs sampling and analysis for HHV, or receives the result of such analysis from the fuel supplier, at the minimum frequency. If a unit larger than 250 mmBtu/hr combusts propane, Tier 3 will be required, and fuel sampling and analysis for carbon content will be required.

Commenter Name: Robert Rouse
Commenter Affiliation: The Dow Chemical Company
Document Control Number: EPA-HQ-OAR-2008-0508-0533.1
Comment Excerpt Number: 22

Comment: Dow Suggests that EPA Modify the Tier 1 Restriction. In §98.33(b)(1), it is restrictive to limit the use of Tier I to units < 250 mmBTU/hr in size. There is no appropriate reason for this restriction, and EPA should not keep this restriction in the final rule. The variations introduced in the calculations will be very small compared to the size of the entire GHG inventory. Dow suggests that EPA eliminate the < 250 mmBTU/hr restriction for the first 3 years of the reporting obligation and then revisit the need for such a restriction after this period of time. Dow Suggests that EPA Modify the Tier 2 Restriction. In §98.33(b)(3), it is restrictive to limit the use of Tier II to units < 250 mmBTU/hr in size. There is no appropriate reason for this restriction, and EPA should not keep this restriction in the final rule. The variations introduced in the calculations will be very small compared to the size of the entire GHG inventory. Dow suggests that EPA eliminate the < 250 mmBTU/hr restriction for the first 3 years of the reporting obligation and then revisit the need for such a restriction after this period of time. Dow Suggests that EPA Clarify that the Tier 4 Method is only Required for Sources that Combust Solid Fossil Fuel with a Maximum Heat Input Capacity Greater Than 250 mmBTU/hr (and for units with a capacity to combust greater than 250 tons per day of MSW) that are Already Equipped with a CEMS System. The requirements contained in proposed §98.33(b)(5) are very confusing as written regarding the applicability of the Tier 4 requirements. The requirements are confusing as to whether they are only required for combustion sources firing solid fuel or MSW, or if they apply to other large (i.e., > 250 MMBtu/hr) combustion units with liquid or gaseous fuels. In addition, the other criteria for MSW and solid fuels listed in Tier 4 are also confusing. Dow believes that EPA has clearly stated the applicability of the Tier 4 requirements on Page 16483 of the Preamble: "The Tier 4 method, and the use of CEMS (with any required monitored upgrades) is required for solid fossil fuel-fired units with a maximum heat input capacity greater than 250 mmBtu/hr (and for units with a capacity greater than 250 tons per day of MSW)." Dow comments that EPA should add this language to §98.33(b)(5)(ii)(A) to clarify the intent of the Tier 4 requirements. Dow comments that EPA should incorporate Table C-1 from page 16481 of the Federal Register containing the Preamble into the actual final rule. This table clearly shows the applicability of Tiers 1 - 4 to various types of combustion units. Dow comments that §98.33(b)(5)(ii) should include the word "and" at the end of each item (A) through (F) to clarify that each one is required and that EPA did not mean "or" between these items.

Response: See the Preamble, Section II. L., on General Monitoring Requirements for the overall rationale for methodologies required under this rule, and the response to comment EPA-HQ-OAR-2008-0508-0909.1 excerpt 4 and EPA-HQ-OAR-2008-0508-0580 excerpt 10 for the rationale for methodologies required under Subpart C.

EPA disagrees with the commenter's suggestion of allowing Tier 1 reporting for all fuels and units of any size. EPA did not choose to adopt a simplified calculation method approach (e.g., using default emission factors) for all units because the data would be less accurate than under the selected option and would not make use of site-specific data that many facilities already have available and refined calculation approaches that many facilities are already using.

However, EPA has significantly expanded the use of Tier 1 and Tier 2 Calculation Methodologies. Most units combusting the biogenic fuels listed in Table C-1 may use Tier 1. The 250 mmBtu/hr restriction on the use of Tier 2 has been lifted for units in which the only fossil fuels combusted are natural gas and/or distillate oil, in view of the homogeneous nature of these fuels. However, the 250 mmBtu/hr unit size cutoff remains for units that combust other fossil fuels.

EPA also acknowledges the commenter's concerns regarding Tier 4 applicability. EPA has revised §98.33(b)(4)(ii) of the final rule to clarify that all six criteria specified in subparagraphs (A) through (F) must be met before Tier 4 is required. The Tier 4 requirement is limited to larger solid fossil fuel units with an existing pollutant CEMS or volumetric flow rate monitor. EPA is requiring the use of CEMS due to the complexity of monitoring solid fuel consumption and the heterogeneous nature of the solid fuels. Many of these fossil fuel-fired units with a pollutant CEMS have an existing diluent monitor (O_2 or CO_2) that can be used to determine CO_2 emissions.

Commenter Name: Juanita M. Bursley
Commenter Affiliation: GrafTech International Holdings Inc. Company (GrafTech)
Document Control Number: EPA-HQ-OAR-2008-0508-0686.1
Comment Excerpt Number: 21

Comment: As written, the citation on page 16634 under §98.33(b)(5)(ii)(c) appears to require any combustion unit that has operated for more than 1,000 hours in any calendar year since 2005 to use the Tier 4 Calculation Method, and therefore would require the installation and operation of CEMS even if this monitoring equipment is not currently installed. (Since there is no "and" provided in the list of criteria, GrafTech has therefore interpreted the requirement to apply to any one listed criterion "or" another.) Firstly, each facility may be unable to establish the annual hours of operation of each stationary fuel combustion unit since 2005, as it was not a past legal requirement to maintain such documentation of operations. There is no convincing reason or known legal precedent to go back to historical operations records several years before a reporting rule becomes effective. Even if this operational documentation is available at a facility, this language is totally unfounded and unnecessary for the same arguments as above, i.e., sufficiently accurate and consistent fuel usage data can be collected and GHG emissions estimated using standard recognized protocols without this additional burden on the regulated community. The number of hours of operation would have negligible impact on the accuracy or consistency of using any of the other recognized GHG emission estimation methods, using readily available fuel usage data and default emission factors available for all the common fuels. Secondly, according to Table C-1 in the Preamble, this criterion only applies to combustion units burning > 250 mmBtu/hour solid fossil fuels or > 250 tons/day municipal solid waste (MSW). Liquid and gaseous fossil fuels, in particular, natural gas, are amongst the cleanest burning and homogenous fuels available, so that this 1,000 hour per year operation time criteria should not apply to them. On page 11 of EPA's Technical Supporting Document (TSD) for the proposed rule, dated Jan 30, 2009, Section 3.2.1 Tier 4 Methodology also indicates that CEMS are being required for large solid fuel units and MSW units, where there is uncertainty in heating value and carbon content. Default emission factors are available and sufficiently accurate for gaseous and liquid fossil fuels, so Tier 1 or Tier 2 (if monthly high heating value information is available) should be acceptable. The §98.33(b)(5)(ii)(c) language in the Final Rule should be written to be clearer and consistent with Table C-1. This language, unless clarified, could conceivably make a large number of covered facilities unnecessarily install and operate CEMS.

Response: EPA acknowledges the commenter's concerns regarding Tier 4 applicability. EPA has revised §98.33(b)(4)(ii) of the final rule to clarify that all six criteria specified in subparagraphs (A) through (F) must be met before Tier 4 is required. The commenter should note that in the final rule, units of any size in which the only fossil fuels combusted are distillate oil and/or pipeline quality natural gas may use Tier 2.

Commenter Name: Marcelle Shoop
Commenter Affiliation: Rio Tinto Services, Inc.
Document Control Number: EPA-HQ-OAR-2008-0508-0636.1
Comment Excerpt Number: 21

Comment: The Tier 3 calculation methodology (98.33(a)(3) requires the reporting entity to rely on direct fuel volume measurements from fuel flow meters, which can include billing meters to determine natural gas or other liquid fuel volumes. The Tier 2 calculation methodology for liquid or gaseous fuels references only reliance on company records, but does not specifically list fuel flow or billing meter measurements as company records. Both with respect to Tier 2 and Tier 3, we assume that billing statements (with metering information) from the fuel or natural gas suppliers may be relied upon to determine fuel volume measurements. However, we request that EPA clarify that combustion sources can rely on such supplier information.

Response: The final rule clarifies that fuel billing meters may be used to quantify fuel consumption, both as a part of company records under Tier 1 and Tier 2, and to directly measure liquid or gaseous fuel flow under Tier 3.

Commenter Name: Lauren E. Freeman
Commenter Affiliation: Hunton & Williams LLP
Document Control Number: EPA-HQ-OAR-2008-0508-0493.1
Comment Excerpt Number: 31

Comment: Although the vast majority of UARG members' combustion units are ARP units that will calculate CO_2 emissions under Subpart D, UARG members also own and operate a variety of non-ARP affected combustion units that could be required to report under this proposed rule. Those may include pre-1990 simple cycle combustion turbines, units serving a generator $\leq$ 25 MW (either pre-1990 units or new units combusting low sulfur fuel), and industrial or auxiliary boilers. In some cases, these units already are monitoring and reporting CO_2 (or O_2) concentration (as diluent) with CEMS and heat input under Part 75 to comply with the NBP or CAIR, or monitoring CO_2 (or O_2) concentration (as diluent) with CEMS under an applicable NSPS. One of UARG's immediate concerns with the rule is ensuring that units that do not already have required monitoring equipment installed have sufficient time to order, install, and perform any necessary testing on that equipment prior to the start of the program. EPA has attempted to address that sort of concern in proposed §98.33(b)(6), which provides that if the monitors needed for Tier 4 reporting have not been installed and certified by January 1, 2010, the unit may use Tier 3 in 2010. While UARG believes that the relief provided by this provision is necessary, it is incomplete. Reporting under Tier 3 also requires monitoring equipment for gaseous fuels -- fuel flow meters and, for some fuels, gas chromatographs -- that may have to be installed and calibrated. In finalizing the rule, EPA must ensure that sufficient time and resources are available for installation and calibration of this equipment.

Response: EPA has revised the rule so that units that must upgrade their existing CEMS to meet Tier 4 requirements and do not have all necessary equipment in place by January 1, 2010 may use either Tier 2 or Tier 3 in 2010. For these units, Tier 4 must be used starting January 1, 2011.

See the Preamble, Section III. G., "Summary of Comments and Responses on Initial Reporting Year and Best Available Monitoring Methods," for additional explanation of flexibility provided to facilities for reporting year 2010.

Commenter Name: Juanita M. Bursley
Commenter Affiliation: GrafTech International Holdings Inc. Company (GrafTech)
Document Control Number: EPA-HQ-OAR-2008-0508-0686.1
Comment Excerpt Number: 20

Comment: The Tier 4 Calculation Method under §98.33(4) is highly burdensome and the required continuous emissions monitoring system (CEMS) is both expensive to install and maintain. Therefore, this method should only be required of reporting facilities that are already required to operate such emissions monitoring equipment under existing rules promulgated under the CAA. The primary purposes of the Mandatory Greenhouse Gas Reporting Rule are to establish a reasonably accurate GHG emissions baseline for the U.S. for use in future rulemaking, and to establish standard procedures to ensure consistent GHG emissions data from year to year for tracking purposes. Given the significant recordkeeping and maintenance burdens associated with operating and maintaining CEMS, the higher level of accuracy afforded by these monitoring systems is neither necessary nor justified by the intended purposes of this rule. If a facility is not required to have CEMS under a Title V Permit for listed priority and hazardous air pollutants, or other CAA programs, because other emissions monitoring and/or estimation methods were deemed adequate, it makes little sense for such a facility to now have to install CEMS to report GHG emissions, when there are adequate methods available to reasonably and consistently estimate these emissions without adding excessive costs and the need for additional resources to install, operate and maintain these monitoring devices. GrafTech believes that EPA should not require CEMS at any reporting facilities, regardless of quantities or types of fuels combusted each year, that are not currently required to have them under other existing air permitting or other regulatory programs, as there is insufficient justification for EPA to make the monitoring or recordkeeping requirements for GHGs more onerous than existing programs for regulated priority pollutants or hazardous air pollutants. This is especially true for purchased gaseous and liquid fossil fuels, which are largely homogenous and for which credible alternative emissions estimation protocols based on metered fuel usage already exist. Similarly, a requirement to install CEM on units for which limited or no other regulatory requirements exist due to "grandfather" status under state air permitting programs appears to be unjustified.

Response: See the response to comment EPA-HQ-OAR-2008-0508-0455.1 excerpt 7 and the response to comment EPA-HQ-OAR-2008-0508-0580 excerpt 10 for EPA's rationale and approach to the use of CEMS.

The Tier 4 requirement is limited to larger solid fossil fuel or MSW units with an existing pollutant CEMS or volumetric flow rate monitor, or a source with an existing CO_2 CEMS and flow rate monitor. EPA is requiring the use of CEMS due to the complexity of monitoring solid fuel consumption and the heterogeneous nature of the solid fuels. Many of these fossil fuel-fired units with a pollutant CEMS have an existing diluent monitor (O_2 or CO_2) that can be used to determine CO_2 emissions.

Commenter Name: Lauren E. Freeman
Commenter Affiliation: Hunton & Williams LLP
Document Control Number: EPA-HQ-OAR-2008-0508-0493.1
Comment Excerpt Number: 32

Comment: For large solid fuel-fired non-ARP units that are already monitoring CO_2 or O_2 under some other program, like the NSPS, UARG disputes EPA's assumption that installing a volumetric flow monitor will not be burdensome. 74 Fed. Reg. at 16,483. Experience under the ARP has shown that volumetric flow monitors can be very sensitive to flow disturbances that occur when monitors are installed in short stacks or ducts or downstream of any potential disturbance. Circular flow and "wall effects" can significantly affect measurements and may need to be accounted for with special testing procedures or, for wall effects, application of correction factors. For these reasons, flow monitors must meet minimum location criteria. Some units may not have an existing location that is suitable for installation of a flow monitor. Moreover, RATA testing of flow monitors, even at the normal level, is significantly more difficult and expensive that RATA testing for CO_2 or O_2, and the cost of adding platforms and access for servicing new volumetric flow monitors can be significant. While UARG does not object to allowing use of a flow monitor if it is already installed, UARG does not believe that installation and certification of a volumetric flow monitor should be required under this rule for any unit. If the information available under Tier 3 is adequate for solid fuel-fired units that do not have CO_2 or O_2 CEMS (and UARG believes that it is), it also is adequate for other units. EPA has not provided an adequate justification for, or estimate of the burdens of, imposing such a requirement.

Response: EPA's estimates of monitoring costs are averages and may not represent the actual cost in individual circumstances. EPA does not agree that Tier 3 monitoring is adequate for all large units that combust solid fossil fuels, particularly if most, or all, of the CEMS infrastructure is already in place. EPA is requiring the use of CEMS due to the complexity of monitoring solid fuel consumption and the heterogeneous nature of the solid fuels. The incremental cost of adding a flow monitor to meet Tier 4 monitoring requirements is not unduly burdensome for a unit that is already required to install, certify, maintain, and operate CEMS, and to perform ongoing QA testing of the existing monitors. EPA's estimated this cost as approximately $25,000 per year (2006 $).

Commenter Name: Kathy G. Beckett
Commenter Affiliation: West Virginia Chamber of Commerce
Document Control Number: EPA-HQ-OAR-2008-0508-0956.1
Comment Excerpt Number: 19

Comment: To comply with §821 of Public Law 101-549, EPA included a number of methodologies in Part 75 to monitor and report CO_2 mass emissions. Although sources are allowed to use CO_2/O_2 CEMS installed as diluent for other purposes, Part 75 also allows use of alternative procedures in Appendix G in lieu of CEMS. Much like Tiers 2 and 3, Appendix G allows CO_2 emissions to be estimated, either by using: (1) fuel feed rates and the results of periodic fuel sampling and analysis (to determine the percent carbon in the fuel), Appendix G, §2.1; or (2) hourly heat input rate measurements from a certified Part 75, Appendix D fuel flow meter and a fuel-specific, carbon-based "F-factor," Appendix G, §2.3. Appendix G is the most frequently-used Part 75 method for estimating CO_2 mass emissions from the oil and gas-fired units that would be required to use Tier 3 under this rule in not ARP affected. Although EPA's proposed rule appropriately allows ARP affected oil and gas-fired units to report annual CO_2 mass emissions calculated using the Appendix G F-factor method to comply with this rule, that option is not provided for other combustion sources and it should be. The F-factors used under Appendix G are well established and apply only to homogeneous liquid and gaseous fuels with little expected variability in their carbon content. EPA recognized this lack of variability in its own proposed Tier 3 methodology, which requires sampling for carbon content only monthly. The Appendix G F-factor method is also based on the same F-factors used by Tier 4 sources with CEMS to convert O_2 CEMS values to CO_2. In short, there is no reason not to allow non ARP combustion sources to use this methodology as well. The accuracy is certainly of sufficient quality to serve the information gathering purposes of this rule.

Response: The commenter should note that EPA has added alternative methods for units that report data to EPA according to Part 75, which allow certain oil- and gas-fired units to use methods from Appendices D and G to Part 75. See §98.33(a)(5) of the final rule.

Commenter Name: Marcelle Shoop
Commenter Affiliation: Rio Tinto Services, Inc.
Document Control Number: EPA-HQ-OAR-2008-0508-0636.1
Comment Excerpt Number: 19

Comment: We urge EPA to make the fuel supplier requirements consistent with the requirements for combustion sources that burn those fuels, while still providing flexibility for the reporter to the greatest extent possible. Allow stationary combustion sources (Tiers 2 or 3) at their option to utilize: 1. Default carbon content or high heating values (sometimes referred to as "HHV") default factors; 2. Carbon content or HHV data provided to the source by the coal-fuel supplier. At a minimum allow the use of default factors for de minimis sources or where carbon content or HHV data are not available from the supplier. Through reliance on business records, EPA presumably intended for stationary combustion sources to be able to make use of supplier information for high heat values (under the Tier 2 calculation methodology) or carbon content and/or molecular weight (under the Tier 3 methodology) as an alternative to conducting on site sampling and analysis. EPA should make the language of the rule clear and explicit that the combustion source can rely on supplier information at its option. We note that this approach is consistent with the draft final WCI Essential Requirements of Mandatory Reporting, which allows facilities to use higher heating values (Calculation Methodology 2) or fuel carbon content or molar fraction (for gaseous fuels) (Calculation Methodology 3) provided by the fuel supplier. See Final Draft Essential Requirements of Mandatory Reporting, WCI.23(b) and (c).

Response: The final rule clarifies that fuel sampling and analysis data provided by the supplier may be used in the emission calculations.

See the response to comment EPA-HQ-OAR-2008-0508-0464.1 excerpt 4 for additional information on the applicability of tiers. EPA did not choose to adopt a simplified calculation method approach for all larger units (e.g., using default factors) because the data would be less accurate than under the selected option and would not make use of site-specific data that many facilities already have available and refined calculation approaches that many facilities are already using.

The commenter should note that units smaller than 250 mmBtu/hr combusting fuels listed in Table C-1 may use Tier 1, provided that the owner or operator does not routinely determine or receive from the fuel supplier the fuel's measured HHV at a frequency greater than or equal to the minimum frequency specified in §98.34. Under Tier 1, a reporter calculates emissions based on fuel consumption from company records and default emission factors and HHVs.

Commenter Name: Kathy G. Beckett
Commenter Affiliation: West Virginia Chamber of Commerce
Document Control Number: EPA-HQ-OAR-2008-0508-0956.1
Comment Excerpt Number: 18

Comment: For large solid-fuel fired non-ARP units that are already monitoring CO_2 or O_2 under some other program, like the NSPS, EPA's assumption that installing a volumetric flow monitor will not be burdensome is not quite accurate. 74 Fed. Reg. at 16483. Experience under the ARP has shown that volumetric flow monitors can be very sensitive to flow disturbances that occur when monitors are installed in short stacks, ducts, or downstream of any potential disturbance. Circular flow and "wall effects" can significantly affect measurements and may need to be accounted for with special testing procedures or, for wall effects, application of correction values. For these reasons, flow monitors must meet minimum location criteria. Some units may not have an existing location that is suitable for installation of a flow monitor. Moreover, RATA testing of flow monitors, even at the normal level, is also significantly more difficult and expensive that RATA testing for CO_2/O_2. While the Chamber does not object to allowing use of a flow monitor if it is already installed, it does not believe that installation and certification of a volumetric flow monitor should be required under this rule for any unit. If the information available under Tier 3 is adequate for solid fuel-fired units that do not have CO_2/O_2 CEMS, it also is adequate for other units. EPA has not provided an adequate justification, or estimation of the burdens, for imposing such a requirement.

Response: EPA's estimates of monitoring costs are averages and may not represent the actual cost in individual circumstances. EPA does not agree that Tier 3 monitoring is adequate for all large units that combust solid fossil fuels fuels, particularly if most, or all, of the CEMS infrastructure is already in place, because of the benefits CEMS provide over calculation approaches in terms of difficulties measuring fuel quality and quantity. EPA is requiring the use of CEMS due to the complexity of monitoring solid fuel consumption and the heterogeneous nature of the solid fuels. The incremental cost of adding a flow monitor to meet Tier 4 monitoring requirements is not unduly burdensome for a unit that is already required to install, certify, maintain, and operate CEMS, and to perform ongoing QA testing of the existing monitors. EPA's estimated this cost as approximately $25,000 per year (2006 $).

Commenter Name: J. P. Blackford
Commenter Affiliation: American Public Power Association (APPA)
Document Control Number: EPA-HQ-OAR-2008-0508-0661.1
Comment Excerpt Number: 18

Comment: APPA supports alternatives to in-stack monitoring in Part 75, e.g. Appendix G to Part 75 that allows gas-fired units to use heat input (derived from fuel flow monitoring data) to calculate CO_2 emissions.

Response: The commenter should note that EPA has added alternative methods for units that report data to EPA according to Part 75, which allow certain oil- and gas-fired units to use methods from Appendices D and G to Part 75. See §98.33(a)(5) of the final rule.

Commenter Name: Lawrence W. Kavanagh
Commenter Affiliation: American Iron and Steel Institute (AISI)
Document Control Number: EPA-HQ-OAR-2008-0508-0695.1
Comment Excerpt Number: 18

Comment: For facilities meeting all of the requirements specified in §98.33(b)(5), Tier 4 requirements are applicable. However, see our comments in reference to coke oven combustion stacks and blast furnace stoves regarding necessary clarifications to §98.33(b)(5). In addition, for those facilities that do qualify for Tier 4, we believe those requirements should only be required for those units that have CO_2 CEMS in place. EPA's requires facilities with CEMS that do not monitor CO_2 to "upgrade" to CO_2 CEMS based on the premise that "incremental costs" will not be duly burdensome. However, the incremental cost of adding CO_2 monitoring when installing a new CEMS is not the same as incremental cost of adding CO_2 monitoring to an existing CEMS, and EPA has understated the cost burden. Moreover, the added benefit of a CO_2 CEMS over the methods specified for Tier 3 is marginal at best, particularly given problems with operational reliability (as noted in our discussion for iron and steel sector monitoring options) and does not justify the added costs.

Response: EPA acknowledges the commenter's concerns regarding Tier 4 applicability. EPA has revised §98.33(b)(4)(ii) of the final rule to clarify that all six criteria specified in subparagraphs (A) through (F) must be met before Tier 4 is required. However, EPA disagrees with suggestions that Tier 4 should only be required if the installed CEMS include a CO_2 monitor. The Tier 4 requirement is limited to larger solid fossil fuel units with an existing pollutant CEMS or volumetric flow rate monitor, or a source with an existing CO_2 CEMS and flow rate monitor. EPA is requiring the use of CEMS due to the complexity of monitoring solid fuel consumption and the heterogeneous nature of the solid fuels. Many of these fossil fuel-fired units with a pollutant CEMS have an existing diluent monitor (O_2 or CO_2) that can be used to determine CO_2 emissions. EPA's estimates of monitoring costs are averages for a representative facility and may not represent the actual cost in individual circumstances.

Commenter Name: Michael Carlson
Commenter Affiliation: MEC Environmental Consulting
Document Control Number: EPA-HQ-OAR-2008-0508-0615
Comment Excerpt Number: 18

Comment: The proposed requirement for daily sampling of all gaseous fuels, except for natural gas, under the General Stationary Fuel Combustion Category (16484) presents a serious disincentive for facilities to use alternative, "green" gaseous fuels, and is inconsistent with efforts by the current administration to promote alternative energy uses.
Response: For gaseous fuels other than natural gas or biogas, due to variability, the daily sampling requirement has been retained, but only for facilities with existing equipment in place that is capable of providing the data. Otherwise, weekly sampling is required. For biogas, quarterly sampling is required.

Commenter Name: Michael Garvin
Commenter Affiliation: Pharmaceutical Research and Manufacturers of America (PhRMA)
Document Control Number: EPA-HQ-OAR-2008-0508-0959.1
Comment Excerpt Number: 17

Comment: PhRMA believes that EPA should require use of methods that are not accepted as common practice in existing regulatory schemes and, where possible, should apply globally accepted methods such those described in EU Directive 2003/97/EC and EU Directive 2007/589/EC. The current language in the proposed rule is not consistent with this standard. As proposed, this rule may have potentially significant impacts on the pharmaceutical industry. These impacts would include the need to install additional monitoring systems on our solid waste incinerators (e.g., pathological waste incinerators, medical/infectious waste incinerators and solid waste incinerators). A number of pharmaceutical facilities operate pathological waste incinerators which are not regulated by detailed federal air quality standards such as the NSPS and NESHAP rules. Given their status under these rules, these units are typically not equipped with elaborate CEM systems. Under the proposed rule, facilities that trigger the 25,000 MT CO_2 eq annual threshold may be required to either upgrade these waste incinerators to install carbon dioxide CEM systems or discontinue their use and outsource the disposal of these materials. Additionally, sites which may be close to the applicability threshold, may need to install and operate elaborate and expensive monitoring systems simply to allow for accurate applicability determinations. PhRMA believes that EPA should not require use of methods that are not accepted as common practice in existing regulatory schemes and, where possible, apply methods accepted globally such as those described in EU Directive 2003/87/EC and EU Directive 2007/589/EC. The existing language regarding CEM systems goes well beyond this.

Response: EPA acknowledges the concerns of the commenter under the assumption that the commenter believes that "EPA should *not* require the use of methods that are not accepted as common practice . . ."

EPA does not intend to require CEMS for this type of unit, and has clarified that all of the criteria specified in §98.33(b)(4)(ii) or (iii) must be present to trigger Tier 4. EPA has also revised the rule to specify that Tier 3 will only be required for units combusting fuels not listed in Table C-1 if the alternative fuel combusted in the unit makes up more than ten percent of the average annual heat input to the unit, and the unit has a maximum rated heat input capacity greater than 250 mmBtu/hr. Provided that CO_2 CEMS are not required or elected, units smaller than 250 mmBtu/hr are only required to report emissions from those fuels listed in Table C-1. Therefore, in this case it appears that only the GHG emissions from combustion of supplementary fossil fuels (if any) in these types of sources must be reported.

EPA respects the effort that may be required to determine applicability and has modified the final rule in order to provide clarity. EPA expects that a source should be able to determine applicability without installing new equipment.

Commenter Name: Michael Carlson
Commenter Affiliation: MEC Environmental Consulting
Document Control Number: EPA-HQ-OAR-2008-0508-0615
Comment Excerpt Number: 17

Comment: The use of Tier 2 or a higher tier for Tier 1 facilities if monthly higher heating values (HHVs) are provided by the fuel supplier should not be mandatory, as proposed by the agency (16484) but optional. From a practical standpoint, how is the agency to know if the fuel supplier provides HHVs monthly?

Response: See the Preamble, Section VI., for the response on rule implementation and enforcement.

EPA believes that it is appropriate to require the use of Tier 2 if the fuel supplier provides HHVs at a frequency greater than or equal to the minimum frequency specified in §98.34. This provision is necessary to ensure that facilities make use of the site-specific data that they already have available. Additionally, fuel providers to stationary sources, particularly coal suppliers, typically provide information to purchasers on the heat content of coal as part of private sector contracts. See the technical support document for Subpart KK Suppliers of Coal.

Commenter Name: Karen St. John
Commenter Affiliation: BP America Inc. (BP)
Document Control Number: EPA-HQ-OAR-2008-0508-0631.1
Comment Excerpt Number: 16

Comment: EPA's proposed CEMS requirements for stationary fuel combustion sources in Subpart C are overly restrictive and need to be made more flexible. In particular, as the proposed rule now reads and which is contrary to the Preamble, the blanket requirement to add a CO_2 monitor to existing CEMS system would impose unnecessary economic burden. The rule should provide greater flexibility to allow the use of other GHG emission determination methodologies. BP also draws EPA's attention to the need to add clarifying syntax to omissions ("and" and "or") to the Tier 4 calculation methodology language for large stationary combustion units that are fired with solid fuels and that have existing CEMS equipment.

Response: EPA acknowledges the commenter's concerns regarding Tier 4 applicability. EPA has revised §98.33(b)(4)(ii) of the final rule to clarify that all six criteria specified in subparagraphs (A) through (F) must be met before Tier 4 is required. However, EPA disagrees with suggestions that Tier 4 should only be required if the installed CEMS include a CO_2 monitor. The Tier 4 requirement is limited to larger solid fossil fuel units with an existing pollutant CEMS or volumetric flow rate monitor, or a source with an existing CO_2 CEMS and flow rate monitor. EPA is requiring the use of CEMS due to the complexity of monitoring solid fuel consumption and the heterogeneous nature of the solid fuels. Many of these fossil fuel-fired units with a pollutant CEMS have an existing diluent monitor (O_2 or CO_2) that can be used to determine CO_2 emissions, and in other cases the existing CEMS can be upgraded to measure CO_2 emissions.

Commenter Name: Lawrence W. Kavanagh
Commenter Affiliation: American Iron and Steel Institute (AISI)
Document Control Number: EPA-HQ-OAR-2008-0508-0695.1
Comment Excerpt Number: 16

Comment: For units with heat inputs less than 250 MMBTUH, Tier 1 methodology would apply. However, given the very large number of combustion units in a typical integrated facility, even this simpler method is unnecessarily burdensome. For example, many plants have only a single metering location for natural gas consumption by the entire plant, and the required addition of individual metering of all units using natural gas would be unnecessarily costly. Section 98.36(c)(3) allows for combined reporting of combustion units that are manifolded and supplied by common fuel piping. We see little difference in expanding this to the entire plant. Besides, the CO_2 emissions from these sources will have already been accounted for in reports required of upstream fuel suppliers.

Response: EPA acknowledges the concerns of the commenter. For units that use Tiers 1, 2, and 3 to calculate CO_2 mass emissions, the cumulative 250 mmBtu/hr heat input capacity limit on the aggregation of units into a group has been dropped. Rather, the 250 mmBtu/hr restriction applies only to the individual units in the group. Therefore, for reporting purposes, individual units with maximum rated heat input capacities of 250 mmBtu/hr or less may be aggregated without limit into a single group, provided that the Tier 4 methodology is not required for any of the units, and all units in the group use the same tier for any common fuel(s) that they combust. In this case it appears that emissions from all of the small units could be reported jointly using Tier 1 or Tier 2 methodologies. There is also an option to group units fed by a common pipe configuration to take advantage of situations where the same fuel is metered centrally and fed to multiple units.

Also, see the Preamble, Section II. L., for EPA's comments on the general monitoring approach.

Commenter Name: Michael DiMauro
Commenter Affiliation: Massachusetts Municipal Wholesale Electric Company (MMWEC)
Document Control Number: EPA-HQ-OAR-2008-0508-0580
Comment Excerpt Number: 11

Comment: EPA should consider reducing, or even eliminating, fuel sampling/analysis requirements for standard types of oil and gas fuels (pipeline gas, No. 2 oil, No. 6 oil, kerosene, etc.), and should instead allow use of default CO_2 emission factors (CO_2 lb/MMBtu or CO_2 lb/unit of fuel consumed) at all Tier levels for units firing standard fuels. For standard gas and oil fuels, the carbon content and the heat content are generally quite consistent (vary by only a few % between samples), so that snap shot site-specific data collection is not expected to improve data accuracies. To the contrary, snap shot data collection of fuel characteristic data could complicate proper identification of GHG emission trends: Variability in site specific GHG emissions caused by random fluctuations (i.e. noise) in fuel characteristic data values resulting from the use of snapshot sampling, errors in the sampling process, and occasional anomalous sample values could act to mask underlying trends in fuel usage and/or differences in fuel usage across facilities. 1. Use of standard default emission factors would avoid this source of data distortion and variability. 2. Policy initiatives for fuel combustion sources are likely to focus improving fuel usage and efficiency patterns, and any factors that could mask such trends would be counterproductive to the development of effective control measures. ii. There is a substantial cost entailed in on-site monthly sampling and analysis of fuels, as well as a significant recordkeeping burden. 1. Collection and transport of natural gas samples can be problematic. 2. Costs of sample analysis are not insignificant. 3. On-site scheduling and tracking of sampling activities represent a significant logistical and manpower burden. It is for these reasons that many Part 75 Appendix D sources use fuel supplier data in lieu of performing on site sampling. iii. As far as I am aware, neither the heat content nor the carbon content of gas and oil fuels can be readily controlled, and therefore they are not likely to be targets for regulation. However, if the tracking of fuel characteristic data is considered of potential benefit, it is suggested that such data be obtained directly from fuel suppliers. Fuel supplier data should be more reliable, complete and consistent than facility data, facilitating the identification of any temporal trends or regional differences in fuel carbon content or GCV values. iv. It should also be noted that Part 75 [CO_2] default Fuel factors are used by all Dilution Extraction CEMS to measure [NO_x, CO, etc.] lb/MMBtu emission rates for compliance determination. It is unclear why such Emission factors should be considered adequate for emission compliance assessments but not for simple emission reporting. It should be noted that while these arguments apply equally to fuel high heat content and to fuel carbon content, indicating that no sampling should be required for either parameter, in practice, a requirement to obtain fuel high heat content data would not represent an onerous burden to the site, if the fuel supplier could serve as the source of such data for all Tier levels.

Response: EPA did not choose to adopt a simplified calculation method approach (e.g., using default emission factors) for all units because the data would be less accurate than under the selected option and would not make use of site-specific data that many facilities already have available and refined calculation approaches that many facilities are already using. However, the use of Tier 2 Calculation Methodologies for CO_2 emissions has been expanded to include units with a maximum rated heat input capacity greater than 250 mmBtu/hr in which the only fossil fuels combusted are pipeline natural gas and/or distillate oil. Furthermore, the sampling frequencies for Tier 2 and Tier 3 have been revised to reduce the burden on reporters. For example, the final rule requires that natural gas be sampled semiannually. For fuel oil and coal, a representative sampling sample is required for each fuel lot, i.e., for each shipment or delivery. The final rule also clarifies that fuel sampling and analysis data provided by the supplier may be used in the emission calculations.

Commenter Name: See Table 3
Commenter Affiliation:
Document Control Number: EPA-HQ-OAR-2008-0508-0433.2
Comment Excerpt Number: 20

Comment: NPRA disagrees with the blanket requirement to add a CO_2 (or O_2 in some cases) monitor to an existing CEMs system that qualifies under the conditions stated in the Preamble. This will impose a substantial and unnecessary economic burden on some facilities. For example, the proposed rule could be construed to require the addition of a CO_2 monitor to a CEMs system that currently only measures stack gas flow, even though no gaseous pollutant monitor is present. In order to accomplish this, not only would the facility be required to purchase and install the CO_2 monitor, it also likely would have to purchase and install a data acquisition and control system (DACS) for the CO_2 monitor; an analyzer calibration system that would be controlled by the DACS to transport the zero and span gases to the stack probe to meet the quality assurance requirement to perform daily zero and span checks; a stack port into which the stack gas sampling probe or monitor, if an in situ monitoring approach is selected and is installed; and possibly a climate controlled monitor shelter to house the additional equipment. In this case, the installation of a CO_2 CEMS would impose substantial capital and operating costs to the facility far beyond those estimated by the EPA in the supporting documentation or those needed to provide the required data using alternative methodologies.

Response: EPA has revised §98.33(b)(4)(ii) of the final rule to clarify that all six criteria specified in subparagraphs (A) through (F) must be met before Tier 4 is required. The Tier 4 requirement is limited to larger solid fossil fuel units with an existing pollutant CEMS or volumetric flow rate monitor, or a source with an existing CO_2 CEMS and flow rate monitor. EPA is requiring the use of CEMS due to the complexity of monitoring solid fuel consumption and the heterogeneous nature of the solid fuels. Many of these fossil fuel-fired units with a pollutant CEMS have an existing diluent monitor (O_2 or CO_2) that can be used to determine CO_2 emissions. The incremental cost of adding a to monitor meet Tier 4 monitoring requirements is not unduly burdensome for a large unit that combusts solid fossil fuels, and is already required to install, certify, maintain, and operate a CEMS or flow rate monitor, and to perform ongoing QA testing of the existing monitors. EPA's estimates of monitoring costs are averages for a representative facility and may not represent the actual cost in individual circumstances. Further detail on the engineering cost analysis for Subpart C can be found in RIA (EPA-HQ-OAR-2008-0318-002), Section 4.3. We are also not aware of instances where only a certified flow rate monitoring system is in place to meet a federal or state requirement.

Commenter Name: Karen St. John
Commenter Affiliation: BP America Inc. (BP)
Document Control Number: EPA-HQ-OAR-2008-0508-0631.1
Comment Excerpt Number: 58

Comment: BP supports EPA's use of fuel-based CH_4 and N_2O emission factors, consistent with aggregation of combustion sources using common fuel gas supplies. Requiring "unit specific" CH_4 and N_2O factors would eliminate the option for aggregation of small sources and the "one-meter" concept where a uniform fuel gas is used throughout a facility and would drive the installation, maintenance, data capture and recording, and QA/QC requirements for metering or monitoring at a unit specific level. Given the small (about 1%) of CO_2e's that CH_4 and N_2O make up from combustion sources this is not cost/value effective. This could be particularly problematic on offshore platform installations.

Response: EPA appreciates the supportive feedback, and has maintained these specifications in the final rule.

Commenter Name: See Table 6
Commenter Affiliation:
Document Control Number: EPA-HQ-OAR-2008-0508-0679.1
Comment Excerpt Number: 117

Comment: §98.38, Table C-3. CH_4 and N_2O factors are not defined, but should be added, for the following fuel types currently listed in §98.38, Table C-1: Ethane; Biogas; Isobutane; n-Butane; Natural Gasoline; Other Oil (> 401 def. F); Pentanes Plus; Petrochemical Feedstocks; Special Naphtha; and Unfinished Oils.

Response: In response to the comment, EPA has extensively revised the default emission factors needed to calculate CH_4 and N_2O emissions, adding generic fuel-based emission factors covering all fuels listed in Table C-1. For example, many of the fuels mentioned by the commenter are covered by the CH_4 and N_2O emission factors for "Petroleum" in Table C-2. EPA has clarified in the final rule that only CH_4 and N_2O emissions from combustion of those fuels listed in Table C-2 of Subpart C are required to be reported.

Commenter Name: See Table 6
Commenter Affiliation:
Document Control Number: EPA-HQ-OAR-2008-0508-0679.1
Comment Excerpt Number: 116

Comment: §98.38, Table C-3 should include default CH_4 and N_2O emission factors for flexi gas, consistent with the emissions factors adopted in California. Flexi gas is a low Btu gas produced during FLEXICOKINGTM, where thermal cracking converts heavy hydrocarbons into light hydrocarbons. The applicable California emission factors for flexi gas (referred to as a derived gas, low BTU gases) are 0.3 g CH_4 per MMBtu and 0.1 g N_2O per MMBtu.

Response: In response to the comment, EPA has extensively revised the default emission factors needed to calculate CH_4 and N_2O emissions, consolidating the emission factors and linking them to the fuel types listed in Table C-1. EPA has revised the final rule so that only CH_4 and N_2O emissions from combustion of those fuels listed in Table C-2 of Subpart C are required to be reported.

Commenter Name: See Table 6
Commenter Affiliation:
Document Control Number: EPA-HQ-OAR-2008-0508-0679.1
Comment Excerpt Number: 115

Comment: §98.38, Table C-1: The emission factor for "Coke" is not specified to be a particular type of coke (e.g. petroleum coke versus catalyst coke).

Response: The coke emission factors in Table C-1, under Coal and Coke, refer to coke derived from coal. There is also an emission factor in Table C-1 specific to petroleum coke under Petroleum Products, and the rule definitions in §98.6 include catalyst coke as a petroleum coke.

Commenter Name: See Table 6
Commenter Affiliation:
Document Control Number: EPA-HQ-OAR-2008-0508-0679.1
Comment Excerpt Number: 103

Comment: Based on Preamble language, API is concerned that the EPA believes any CEMS can be easily converted to a CO_2 CEMS in Tier 4. API disagrees that this is a simple conversion. For this reason, clarification should be added to §98.33(b)(5)(ii). In addition, clarification should be added to §98.33(b)(5)(ii)(D) and (E) to indicate whether the "installed CEMS" are any type of CEMS (i.e. criteria pollutant CEMS or CO_2 CEMS) or a specific type of CEMS (e.g. CO_2 CEMS). For gaseous fuels metering of fuel volume coupled with analysis of carbon content is likely to be more accurate than direct measurement of CO_2 emissions with a CEM. API will provide additional information on this topic.

Response: EPA has revised §98.33(b)(4)(ii) of the final rule to clarify that all six criteria specified in subparagraphs (A) through (F) must be met before Tier 4 is required. EPA disagrees with suggestions that Tier 4 should only be required if the installed CEMS include a CO_2 monitor. The Tier 4 CEMS requirement is limited to larger solid fossil fuel or MSW units with an any type of existing pollutant CEMS or volumetric flow rate monitor, or a source with an existing CO_2 CEMS and flow rate monitor.

Commenter Name: See Table 6
Commenter Affiliation:
Document Control Number: EPA-HQ-OAR-2008-0508-0679.1
Comment Excerpt Number: 100

Comment: §98.33: Offshore facilities submit triannually an emission inventory to MMS under the GOADS system for criteria pollutants. Offshore facilities should be allowed to use the same calculations under the GOADS[7] systems for GHG reporting since MMS has been granted jurisdiction for offshore air emissions.
Response: See the Preamble, Section II. O., for the response on the relationship of this rule to other programs. EPA requires all facilities to report annually directly to EPA to ensure timely reporting of data in a consistent format, subject to consistent verification procedures.

Commenter Name: See Table 6
Commenter Affiliation:
Document Control Number: EPA-HQ-OAR-2008-0508-0679.1
Comment Excerpt Number: 98

Comment: In Subpart MM (Suppliers of Petroleum Products), EPA requests "comment on whether reporters should be allowed to combine default CO_2 emission factors to develop alternative factors for fuel reformulations according to the volume percent of each fuel component" (p. 16572). This issue also affects Subpart C. As there are currently no default emission factors for fuel mixtures, Tiers 1 and 2 cannot be used to estimate combustion emissions from fuel mixtures. However, since CO_2 emissions are based on the carbon content of the fuels, multiplying the volume of each pre-mixed fuel by its respective fuel-based emission factor would result in an accurate estimate of CO_2 for the fuel mixture. Clarification should be added to Subpart C as to how emissions from fuel mixtures should be estimated, without the use of carbon content measurements or CEMS. III.3, API requests that the reporting rule allow up to 5% of the emissions to be declared as "de minimis", allowing simplified emission estimation methods for demonstrating compliance with this emission level. This should include small combustion sources.

Response: See the Preamble, Section II., K., for the response on de minimis reporting for small emission points.

While EPA does not agree that there should be a de minimis emissions exclusion, the Agency has expanded the list of exempted source categories to include portable equipment, emergency generators, and flares. In addition, units that combust hazardous waste will not be required to report GHG emissions given specific provisions stated in §98.30(c). EPA has also removed the cumulative 250 mmBtu/hr restriction on unit aggregation, and believes that the expanded availability of this option will reduce the reporting burden on facilities.

Where different types of fuel are blended prior to combustion, and Tier 2 or 3 is used, EPA has added an option to either use a weighted HHV or carbon content value in the emission calculations based on the relative proportions of each fuel in the blend, or take a representative sample of the blended fuel and analyze it for HHV or carbon content. Section 98.33(b)(6) provides clarification regarding the use of the tiers for units combusting more than one fuel. The commenter should note that units reporting under Tier 3 are only expected to report emissions from fuels that contribute more than ten percent of the unit's annual heat input.

Commenter Name: See Table 6
Commenter Affiliation:
Document Control Number: EPA-HQ-OAR-2008-0508-0679.1
Comment Excerpt Number: 97

Comment: 11. EPA states : [...] given the unit-level approach for calculating CO_2 emissions, EPA is requesting comments on the use of more technology-specific CH_4 and N_2O emission factors that could be applied in unit-level calculations." (p. 16485) API Comments: API supports EPA's use of fuel-based CH_4 and N_2O emission factors, consistent with aggregation of combustion sources using common fuel gas supplies. Requiring "unit specific" CH_4 and N_2O factors would eliminate the option for aggregation of small sources and the "one-meter" concept where a uniform fuel gas is used throughout a facility and would drive the installation, maintenance, data capture and recording, and QA/QC requirements for metering or monitoring at a unit specific level. Given the small (about 1%) of CO_2e's that CH_4 and N_2O make up from combustion sources this is not cost/value effective. This could be particularly problematic on offshore platform installations.

Response: EPA appreciates the supportive feedback, and has maintained these specifications in the final rule.

Commenter Name: See Table 10
Commenter Affiliation:
Document Control Number: EPA-HQ-OAR-2008-0508-0635
Comment Excerpt Number: 76

Comment: EPA's proposed rule includes flaring in the fugitive emission category. Flares are combustion sources and are included in EPA's combustion equipment inventories for criteria air pollutants, and in current industry GHG combustion equipment inventories. Flares are a large source of GHG emissions. We recommend that all flare sources be required to report GHG emissions, and these emissions be included in the combustion equipment category as a standalone source. While some operators have taken steps to minimize flaring emissions, this is still a very large viable GHG emission reduction target, with known cost-effective emission reduction opportunities.

Response: EPA acknowledges the concerns of the commenter, but has concluded that in many cases flare sources are not significant, considering the small quantity of emissions captured and the expense associated with their quantification. EPA has revised the list of exemptions from the general stationary combustion source category to exclude flares (see §98.30(b)(3)) from Subpart C, so long as flare emissions are not required to be reported by another subpart. Note that Subpart W Oil and Gas Operations is not being finalized at this time.

Commenter Name: Karen St. John
Commenter Affiliation: BP America Inc. (BP)
Document Control Number: EPA-HQ-OAR-2008-0508-0631.1
Comment Excerpt Number: 71

Comment: Biogenic carbon is carbon derived from biogenic (plant or animal) sources (excluding fossil carbon) that have been fixed from atmospheric carbon dioxide through photosynthesis. Biogenic carbon is part of the natural carbon cycle where there is a continuous exchange of carbon between the biosphere and the atmosphere. BP recommends that the calculation methodology for quantifying CO_2 emissions from the combustion of biogenic material in Subpart C Section 98.33(e) should be removed to make its treatment more consistent with the Kyoto Protocol. By international reporting convention, CO_2 emissions from the combustion of biogenic material are zero by definition. The international reporting convention was designed to enable the reporting of robust and complete national GHG emission inventories without double counting and forms the basis of the international flexible mechanisms within the Kyoto Protocol. BP accepts the logic of the international convention for the reporting of CO_2 from the combustion of biomass and considered carbon neutral and recommends that CO_2 emissions from the combustion of biogenic carbon not be included in the final rule. Biofuels production facilities should only be required to report emissions from on-site stationary combustion of fossil fuels. BP anticipates that a number of technologies and processes would utilize biomass to power advanced and cellulosic biofuels production facilities. For example, in Brazil, where over 50% of the nation's fuel is comprised of biofuels, biomass is the source of power for most biofuels production facilities. In much the same manner, it is likely that cellulosic biofuels facilities built in the U.S. to meet federal mandates would utilize biomass to produce the power necessary to run the production facility.

Response: See the response to comment EPA-HQ-OAR-2008-0508-0690.1 excerpt 1 corresponding to Section II. of the Preamble, and the response to comment EPA-HQ-OAR-2008-0508-0631.1 excerpt 71 corresponding to Subpart C for additional explanation of the reporting of biogenic CO_2 emissions.

Including reporting of biogenic CO_2 at facilities that are already reporting for stationary combustion provides EPA with information on the use of biofuels as they relate to reductions of fossil CO_2 emissions over time. This reporting requirement also provides additional data for verification. EPA believes that it is clear in §98.2, however, that CO_2 emissions from biogenic fuels do not count toward the 25,000 metric ton threshold for reporting for stationary combustion units, although CH_4 and N_2O emissions from biogenic fuels must be considered when calculating the threshold and determining applicability.

EPA has specified in §98.33 that in most cases Tier 1 may be used to calculate emissions from the combustion of biogenic fuels listed in Table C-1 in a unit of any size.

Also see the Preamble, Section II. C., for EPA's response to comments on GHGs to report.

Commenter Name: Karen St. John
Commenter Affiliation: BP America Inc. (BP)
Document Control Number: EPA-HQ-OAR-2008-0508-0631.1
Comment Excerpt Number: 64

Comment: It is apparent from EPA's construct and use of the 4 Tier Monitoring system and the discussion in the Preamble that EPA presumes that CEMS are the most accurate methodology to estimate CO_2 emissions. BP has evaluated this premise and illustrated that metering of gaseous fuels combined with carbon content analysis of the fuel (gas) has more inherent accuracy than use of a CEMS for determining CO_2 emissions. The typical types of gas meters used in the industry will all return better relative accuracy than use of a CEMS. [See DCN: EPA-HQ-OAR-2008-0508-0631.1 for Tables showing Fuel Meter Method Uncertainty and CEMS Uncertainty]

Response: See the response to comment EPA-HQ-OAR-2008-0508-0455.1 excerpt 7 and the response to comment EPA-HQ-OAR-2008-0508-0580 excerpt 10 for EPA's rationale and approach to the use of CEMS.

EPA has revised §98.33(b)(4)(ii) of the final rule to clarify that all six criteria specified in subparagraphs (A) through (F) must be met before Tier 4 is required. The Tier 4 CEMS requirement is limited to larger solid fossil fuel and MSW units with an existing pollutant CEMS or volumetric flow rate monitor, or a source with an existing CO_2 CEMS and flow rate monitor.

Commenter Name: Marcelle Shoop
Commenter Affiliation: Rio Tinto Services, Inc.
Document Control Number: EPA-HQ-OAR-2008-0508-0636.1
Comment Excerpt Number: 25

Comment: The proposed rule only requires facilities with installed CEMS to use CEMS. One of the criteria for determining whether a facility with installed CEMS must use the Tier 4 Calculation Methodology is that the "installed CEMS include a gas monitor of any kind." (74 Fed. Reg. at 16634, proposed §98.33(b)(5)(ii)(E) Rio Tinto supports EPA's decision to require CEMS only at facilities that already have installed CEMS. A Rio Tinto facility has an installed continuous opacity monitoring system. Since this device does not measure gas, we seek clarification from EPA that an opacity monitor is NOT a "gas monitor of any kind."

Response: EPA has added language to the final rule clarifying that only sources meeting all of the requirements in §98.33(b)(4)(ii) or (iii) will be required to use Tier 4 methods. Sources operating only COMS will not be required to use Tier 4. EPA does not believe that any further language is necessary to address this issue.

Commenter Name: Karen St. John
Commenter Affiliation: BP America Inc. (BP)
Document Control Number: EPA-HQ-OAR-2008-0508-0631.1
Comment Excerpt Number: 59

Comment: In Subpart MM (Suppliers of Petroleum Products), EPA requests "comment on whether reporters should be allowed to combine default CO_2 emission factors to develop alternative factors for fuel reformulations according to the volume percent of each fuel component" (p. 16572). This issue also affects Subpart C. As there are currently no default emission factors for fuel mixtures, Tiers 1 and 2 cannot be used to estimate combustion emissions from fuel mixtures. However, since CO_2 emissions are based on the carbon content of the fuels, multiplying the volume of each pre-mixed fuel by its respective fuel-based emission factor would result in an accurate estimate of CO_2 for the fuel mixture. BP requests that EPA clarify how emissions from fuel mixtures should be estimated, without the use of carbon content measurements or CEMS.

Response: Where different types of fuel are blended prior to combustion, and Tier 2 or 3 is used, EPA has added an option to either use a weighted HHV or carbon content value in the emission calculations based on the relative proportions of each fuel in the blend, or take a representative sample of the blended fuel and analyze it for HHV or carbon content. §98.33(b)(6) provides clarification regarding the use of the tiers for units combusting more than one fuel. The commenter should note that units reporting under Tier 3 are only expected to report emissions from fuels that contribute more than ten percent of the unit's annual heat input.

Commenter Name: Lawrence W. Kavanagh
Commenter Affiliation: American Iron and Steel Institute (AISI)
Document Control Number: EPA-HQ-OAR-2008-0508-0695.1
Comment Excerpt Number: 14

Comment: Subpart C requires reporting of combustion unit CH_4 and N_2O emissions using default values for various fuels shown in Table C-3. No values are presented for blast furnace gas. We are not aware of any reliable emission factors for these gases for blast furnace gas combustion but believe concentrations of these gases to be insignificant, if present at all, in the combustion products of blast furnace gas and suggest deleting this requirement for blast furnace gas combustion sources.

Response: EPA acknowledges the concerns of the commenter. Section 98.33(c) of the final rule excludes from calculations any CH_4 and N_2O emissions from fuels that are not listed in Table C-2 of Subpart C. Table C-2 has been revised to include CH_4 and N_2O emission factors for more fuels, including blast furnace gas and coke oven gas, as well as generic emission factors covering all fuel types listed in Table C-1. EPA has also deleted the provision which allowed facilities burning other fuels to develop site-specific emission factors based on the results of source testing.

Commenter Name: Gregory A. Wilkins
Commenter Affiliation: Marathon Oil Corporation
Document Control Number: EPA-HQ-OAR-2008-0508-0712.1
Comment Excerpt Number: 56

Comment: Marathon proposes that natural gas pilots should be allowed the use of engineering estimates for their contribution to heater BTU values. Natural gas pilots represent less than 5% of the heater designed BTU value and do not have flow meters. For most refinery heaters the pilot gas system is separate from the main combustion systems. Marathon has concerns that EPA would require a flow meter on this stream if emissions are required to be reported on a unit by unit basis. Because these are such small streams and because there are numerous streams located in the facilities, this would represent a large cost and burden to install and maintain any equipment needed.

Response: EPA has removed the cumulative 250 mmBtu/hr restriction on unit aggregation and has clarified the use of common pipe metering. While emissions from natural gas pilots such as these should be reported, it is not necessary to add individual fuel flow meters on each pilot. Instead, a single fuel flow meter on the pipe supplying natural gas to multiple pilots or other units at the facility may be used. EPA believes that the expanded availability of these options will reduce the reporting burden on facilities.

Commenter Name: Gregory A. Wilkins
Commenter Affiliation: Marathon Oil Corporation
Document Control Number: EPA-HQ-OAR-2008-0508-0712.1
Comment Excerpt Number: 54

Comment: Marathon opposes the requirement of monthly monitoring of natural gas used within the facility. Pipeline quality natural gas is homogenous and its qualities do not change. The use of supplier data should be allowed for natural gas as with other fuels, with a frequency of providing that data no more often than monthly as offered elsewhere in the rule (for example the monthly supplier heating values allowed in 98.33(b)(l)(ii)). This data would meet the requirements for the reporting rule as there is almost no possibility of these parameters changing if there are no streams being added to the incoming natural gas stream from the point where the supplier is monitoring to the point where it comes on site. This is an unnecessary requirement to mandate as efforts will only be duplicated with no added benefit. In addition, natural gas sample equipment required to be added on the line to collect samples will be costly. Marathon would propose to remove the requirement from the Tier 3 methodology requiring monthly sampling of natural gas and instead allow the submission of supplier provided carbon content data.

Response: The commenter should note that EPA has expanded the use of the Tier 2 Calculation Methodology to units of any size in which the only fossil fuels combusted are pipeline quality natural gas and/or distillate oil. Furthermore, the mandatory fuel sampling and analysis requirements for Tiers 2 and 3 have been considerably revised. EPA agrees with the commenter that for a homogeneous fuel such as pipeline natural gas, monthly sampling is not necessary. Therefore, §98.34 has been revised to require that natural gas be sampled semiannually.

The final rule clarifies that fuel sampling and analysis data provided by the supplier may be used in the emission calculations, and that fuel billing meters may be used to quantify fuel consumption. To simplify the emission calculations in Tiers 2 and 3, arithmetic averaging of HHV and carbon content data is permitted if these data are obtained at least at the minimum frequency specified in §98.34, but less frequently than monthly (see §98.33(a)(2)(ii)). If sampling is more frequent, the reporter must calculate a weighted average according to Equation C-2b. However, regardless of the sampling frequency, the owner or operator must use the results of all available valid fuel analyses in the emissions calculations.

Commenter Name: Sam Chamberlain
Commenter Affiliation: Murphy Oil Corporation
Document Control Number: EPA-HQ-OAR-2008-0508-0625
Comment Excerpt Number: 39

Comment: EPA requests "comment on whether reporters should be allowed to combine default CO_2 emission factors to develop alternative factors for fuel reformulations according to the volume percent of each fuel component" (Preamble, p. 648). As there are currently no default emission factors for fuel mixtures, Tiers 1 and 2 cannot be used to estimate combustion emissions from fuel mixtures. Murphy operates two refineries and twelve terminals across the USA performing various blending mixtures. This issue also affects Subpart C. Since CO_2 emissions are based on the carbon content of the fuels, multiplying the volume of each pre-mixed fuel by its respective fuel-based emission factor would result in an accurate estimate of CO_2 for the fuel mixture. Clarification should be added to Subpart C as to how emissions from fuel mixtures should be estimated, without the use of carbon content measurements or CEMS.

Response: Where different types of fuel are blended prior to combustion, and Tier 2 or 3 is used, EPA has added an option to either use a weighted HHV or carbon content value in the emission calculations based on the relative proportions of each fuel in the blend, or take a representative sample of the blended fuel and analyze it for HHV or carbon content. §98.33(b)(6) provides clarification regarding the use of the tiers for units combusting more than one fuel. The commenter should note that units reporting under Tier 3 are only expected to report emissions from fuels that contribute more than ten percent of the unit's annual heat input.

Commenter Name: Rich Raiders
Commenter Affiliation: Arkema Inc.
Document Control Number: EPA-HQ-OAR-2008-0508-0511.1
Comment Excerpt Number: 38

Comment: Arkema does not understand why individual reporters should be required to determine the high heating value ("HHV") of commodity quality fuels being burned in Part 98 reporting units. Pipeline and commodity fuel distributors manage HHV values for their fuel streams within their processes. EPA correctly notes that most commodity fuel manufacturers do not currently disclose HHV data to their customers, but could readily distribute this information to their customers. EPA should revise proposed Subpart C to allow reporters to utilize vendor-provided HHV in lieu of developing periodic HHV data from commodity fuels.

Response: The final rule clarifies that fuel sampling and analysis data provided by the supplier may be used in the emission calculations.

Commenter Name: Rich Raiders
Commenter Affiliation: Arkema Inc.
Document Control Number: EPA-HQ-OAR-2008-0508-0511.1
Comment Excerpt Number: 37

Comment: Owners and operators of commodity fuels may use the Tier 1 or 2 compliance systems to report CO_2e emissions from fuel combustion sources using commodity fuels. EPA should allow operators of thermal APCD to use total supplemental fuel delivered to the APCD to calculate CO_2e emissions from such devices. Many reporters can, and are required to, calculate with reasonable accuracy, using existing CAA required approaches, the total APCD input stream over the course of a year. Where these total APCD input loading calculations already exist, EPA should allow the reporters to utilize this existing information to calculate CO_2e values for each device as a compliance option for proposed Subpart C Tier 3 reporting requirements. The Tier 3 daily BTU analysis, molecular weight determination, and carbon content determination are redundant with existing requirements to determine total load into APCD.

Response: EPA acknowledges the concerns of the commenter and has revised §98.33 to deal with certain unconventional combustion processes and types of fuel. In the Preamble, EPA has explained that "devices such as thermal oxidizers and pollution control devices . . . would report only the GHG emissions from the firing of supplemental fossil fuels." EPA believes that these provisions satisfy the intent of Part 98, to collect accurate and consistent GHG emissions data that can be used to inform future decisions.

Commenter Name: See Table 5
Commenter Affiliation:
Document Control Number: EPA-HQ-OAR-2008-0508-0480.1
Comment Excerpt Number: 36

Comment: Tiers 1 and 2 indicate that fuel combusted must be based on company records and the operator must provide an explanation and data used to determine fuel consumption. Natural gas sector operators are required to report combustion emissions for pollutants (e.g., NO_x, VOCs, etc.) under Clean Air Act and state programs. For consistency, those technical approaches for fuel use determination should be allowed under Subpart C. As an example, fuel consumption is determined based on operating hours, source rated capacity, and brake specific fuel consumption (i.e., Btu/hp-hr fuel use, which is a measure of unit operating efficiency). INGAA's understanding is that the operator has discretion to use such approaches to determine fuel consumption for Tier 1 and Tier 2 and that current practice acceptable for other emissions reporting obligations are acceptable for GHG reporting under Subpart C.

Response: EPA acknowledges the commenter's concerns, and has defined the term "company records" in §98.6 of the final rule. EPA believes that the revised definition provides appropriate guidance as to what records a facility may use to determine fuel consumption.

Commenter Name: See Table 5
Commenter Affiliation:
Document Control Number: EPA-HQ-OAR-2008-0508-0480.1
Comment Excerpt Number: 35

Comment: To avoid confusion during implementation and provide reporting consistency, INGAA recommends that EPA specify the horsepower (hp) equivalent to 250 MMBtu/hr. Combustion capacity at many facilities is permitted based on horsepower rating rather than firing rate, and presenting the horsepower equivalent will ensure that the aggregation threshold is consistently implemented for subject facilities. INGAA recommends that the rule indicate that aggregation for combustion reporting can be based on 250 MMBtu/hr or 30,000 hp. Similarly, the 30,000 hp equivalency to 250 MMBtu/hr should be used for defining whether a Tier 1 or Tier 2 approach can be used for an individual source (i.e., larger sources must use Tier 3 or Tier 4).

Response: See the Preamble, Section II. E., and the response to comment EPA-HQ–OAR-2008-0508-0350.1 excerpt 3 for additional explanation of the selection and form of thresholds.

EPA acknowledges the concerns of the commenter but as demonstrated by the commenter it is straightforward for reporters to establish equivalencies for horsepower and heat input to be used internally as guides. To avoid confusion associated with multiple thresholds in different units, EPA will not define a horsepower equivalent to the 250 mmBtu/hr maximum rated heat input capacity in the final rule. EPA plans to issue additional guidance to help potential reporters determine applicability and the use of tiers.

Commenter Name: See Table 6
Commenter Affiliation:
Document Control Number: EPA-HQ-OAR-2008-0508-0679.1
Comment Excerpt Number: 35

Comment: API would like to emphasize a major discrepancy between the Preamble discussion and the rule language under Subpart C: The Preamble states that continuous emission monitoring systems (CEMS) are only required for combustion devices fired by solid fuels, as listed in Table C-1 on page 16481; The rule language regarding selection of the "Tier" level for monitoring and measurement methods does not reflect the discussion and intent in the Preamble; Section 98.33(b)(5), as currently written, would require CEMS for any combustion unit that ran for more than 1,000 hours in any year since 2005; There seems to be some syntax omissions, including some "and" and "or" omissions in the current rule language. These omissions seem to contravene the Preamble intent as summarized in Table C-1. API is providing in Exhibit 3 below an excerpt of the rule language with specific edits for amending the rule language to reflect the intent and rationale presented in the Preamble, and as summarized in Table C-1 (74 FR 68, page 16481). Exhibit 3 – Recommended rule language amendment (74 FR 16634, April

10, 2009) (b) Use of the four tiers. (5) The Tier 4 Calculation Methodology: (i) May be used for a unit of any size, combusting any type of fuel. (ii) Shall be used for a unit if: (A) The unit has a maximum rated heat input capacity greater than 250 mmBtu/hr, or if the unit combusts municipal solid waste and has a maximum rated input capacity greater than 250 tons per day of MSW, and (B) The unit combusts solid fossil fuel or MSW, either as a primary or secondary fuel, and (C) The unit has operated for more than 1,000 hours in any calendar year since 2005, or (D) The unit meets the criteria in (B) and (C) directly above, and (E) The unit has installed CEMS that are required either by an applicable Federal or State regulation or the unit's operating permit, and (F) The installed CEMS include a gas monitor of any kind, a stack gas volumetric flow rate monitor, or both and the monitors have been certified in accordance with the requirements of part 75 of this chapter, part 60 of this chapter, or an applicable State continuous monitoring program, and (G) The installed gas and/or stack gas volumetric flow rate monitors are required, by an applicable Federal or State regulation or the unit's operating permit, to undergo periodic quality assurance testing in accordance with appendix B to part 75 of this chapter, appendix F to part 60 of this chapter, or an applicable State continuous monitoring program. (iii) Shall be used for a unit with a maximum rated heat input capacity of 250 mmBtu/hr or less and for a unit that combusts municipal solid waste with a maximum rated input capacity of 250 tons of MSW per day or less, if the unit: (A) Has both a stack gas volumetric flow rate monitor and a CO_2 concentration monitor, and (B) The unit meets the other conditions specified in paragraphs (b)(5)(ii)(B) and (C) of this section, and (C) The CO_2 and stack gas volumetric flow rate monitors meet the conditions specified in paragraphs (b)(5)(ii)(D) through (b)(5)(ii)(F) of this section.

Response: EPA acknowledges the commenter's concerns regarding Tier 4 applicability. EPA has revised §98.33(b)(4) of the final rule to clarify that either all six criteria specified in §98.33(b)(4)(ii) subparagraphs (A) through (F) or all three criteria specified in §98.33(b)(4)(iii) subparagraphs (A) through (C) must be met before Tier 4 is required.

Commenter Name: Lauren E. Freeman
Commenter Affiliation: Hunton & Williams LLP
Document Control Number: EPA-HQ-OAR-2008-0508-0493.1
Comment Excerpt Number: 34

Comment: EPA proposes to require that all ARP affected units, and "other units monitoring heat input year round under §75.10(c)" and reporting heat input under §75.64, use Part 75 heat input data (in mmBtu) and a fuel-specific emission factor from Table C-3 to report CH_4 and N_2O. Proposed §98.33(c). For all other units, EPA proposes to require use of (1) measured HHV, if measured or provided at least monthly, and (2) if not measured monthly, the default HHV specified in Table C-1. Proposed section 98.33(c). UARG again appreciates the opportunity to use quality-assured data reported under Part 75. However, UARG has the same concerns regarding use of missing data procedures and bias adjustment factors for CH_4 and N_2O as described above for CO_2. As a result, UARG requests that the same alternative be provided for missing volumetric flow data and Appendix D fuel flow data as requested above for Subpart D. UARG also notes that it would not necessarily agree to use of bias-adjusted volumetric flow data to calculate heat input, and mass emission of CH_4 and N_2O, in a possible future program regulating GHG.

Response: See the Preamble, Section III. C., the Subpart D comment response document volume, and response to comment EPA-HQ-OAR-2008-0508-0956.1 excerpt 20 for the rationale for using substitute data reported under Part 75.

EPA acknowledges the commenter's concerns, but believes that it is appropriate to use the heat input data reported under Part 75 for the purposes of calculating CH_4 and N_2O emissions from Part 75 units. As the commenters point out, this data is already quality-assured and reported to EPA, and it is consistent with EPA's overall approach to require minimum additional reporting for facilities already reporting CO_2 to EPA. EPA does not believe that it is appropriate to provide any alternative missing data procedures for Part 75 units. Requiring additional missing data procedures would require additional verification of data currently being reported by these units.

Commenter Name: Lauren E. Freeman
Commenter Affiliation: Hunton & Williams LLP
Document Control Number: EPA-HQ-OAR-2008-0508-0493.1
Comment Excerpt Number: 33

Comment: Although EPA's proposed rule appropriately allows ARP affected oil- and gas-fired units to comply with this rule by reporting annual CO_2 mass emissions calculated using the Appendix G "F-factor method," that option is not provided for other combustion sources. UARG believes that it should be. The F-factors used under Appendix G are well established and apply only to homogeneous liquid and gaseous fuels with little expected variability in their carbon content. EPA recognized this lack of variability in its own proposed Tier 3 methodology, which requires sampling for carbon content only monthly. The Appendix G "F-factor method" is also based on the same F-factors used by Tier 4 sources with CEMS to convert O_2 CEMS values to CO_2. In short, UARG sees no reason not to allow non-ARP stationary combustion sources owned or operated by electric generating companies to use this methodology as well. The accuracy is certainly of sufficient quality to serve the information gathering purposes of this rule.

Response: The commenter should note that EPA has added alternative methods for units that report data to EPA according to Part 75, which allow certain oil- and gas-fired units to use methods from Appendices D and G to Part 75. See §98.33(a)(5) of the final rule.

Commenter Name: See Table 5
Commenter Affiliation:
Document Control Number: EPA-HQ-OAR-2008-0508-0480.1
Comment Excerpt Number: 33

Comment: As Section §98.33(a) identifies a tiered approach for determining combustion CO_2 emissions. INGAA supports this approach, which provides flexibility based on the information that is available while providing accurate combustion CO_2 estimates. For natural gas-fired sources, fuel quality will typically be stable over extended time periods, thus an annual average value for gas quality parameters and annual fuel use should be allowed for calculating combustion CO_2 emissions for Tiers 2 and 3. This will minimize unnecessary reporting burden.

Data quality can be assured via records that document consistent fuel quality. In addition, to avoid any potential for future confusion, INGAA requests clarification regarding application of the Tier 4 approach, which relies on continuous emissions monitoring systems (CEMS). CEMS are required for some large electric generating units and other select sources, and optional for other sources. §98.33(b)(5)(ii) identifies criteria that mandate CEMS, and it is apparent based on the Preamble discussion that all of the criteria in (ii) must apply. However, when not clearly specified, regulatory criteria can be interpreted as or rather than and criteria. To avoid any potential for confusion, §98.33(b)(5)(ii) should be revised to indicate that Tier 4, "shall be used for a unit if all of the following apply:"

Response: In the final rule, the use of the Tier 2 Calculation Methodologies for CO_2 emissions has been expanded to include units greater than 250 mmBtu/hr in which the only fossil fuels combusted are pipeline natural gas and/or distillate oil. The revised Tier 2 methods allow emissions to be calculated based on total annual fuel consumption and average measured HHV, calculated according to specifications in the rule. In addition, the mandatory fuel sampling and analysis requirements for Tiers 2 and 3 have been considerably revised. Section 98.34 in the final rule requires that natural gas be sampled semiannually.

EPA acknowledges the commenter's concerns regarding Tier 4 applicability. EPA has revised §98.33(b)(4)(ii) of the final rule to clarify that all six criteria specified in subparagraphs (A) through (F) must be met before Tier 4 is required.

Commenter Name: Karen St. John
Commenter Affiliation: BP America Inc. (BP)
Document Control Number: EPA-HQ-OAR-2008-0508-0631.1
Comment Excerpt Number: 60

Comment: Offshore facilities tri-annually submit an emission inventory to the U.S. Department of Interior Minerals Management Service (MMS) under the GOADS system for criteria pollutants. Offshore facilities should be allowed to use the same monitoring, data, and approach as used for the GOADS inventory.

Response: See the Preamble, Section II. O., for the response on the relationship of this rule to other programs. EPA requires all facilities to report annually directly to EPA to ensure timely reporting of data in a consistent format, subject to consistent verification procedures.

Commenter Name: Michael DiMauro
Commenter Affiliation: Massachusetts Municipal Wholesale Electric Company (MMWEC)
Document Control Number: EPA-HQ-OAR-2008-0508-0580
Comment Excerpt Number: 14

Comment: Units subject to Tier III monitoring should be provided the option of conforming with 40 FCR 75 Appendix D fuel metering/fuel sampling procedures and data reduction procedures to determine CO_2.

Response: EPA has expanded the use of the Tier 2 Calculation Methodology to include units greater than 250 mmBtu/hr that combust only pipeline natural gas and/or distillate oil. This would affect non-ARP units referenced by the commenter. The monthly fuel sampling and analysis requirements for Tiers 2 and 3 have been considerably revised. §98.34 of the final rule requires that natural gas be sampled semiannually. For other fuels such as oil and coal, which are delivered in shipments or lots, requiring monthly sampling may be impractical. For fuel oil and coal, a representative sampling is required for each fuel lot, i.e., for each shipment or delivery. For other liquid fuels and biogas, quarterly sampling is required.

In addition, alternative methodologies have been added to the rule, allowing sources that monitor and report heat input according to Part 75, but are not required to report CO_2 mass emissions, to use established Part 75 CO_2 emissions calculation methods to meet the Part 98 reporting requirements. See §98.33(a)(5).

Commenter Name: Lawrence W. Kavanagh
Commenter Affiliation: American Iron and Steel Institute (AISI)
Document Control Number: EPA-HQ-OAR-2008-0508-0695.1
Comment Excerpt Number: 15

Comment: Coke oven gas not used for oven underfiring and blast furnace gas not used in stoves are distributed as useful fuels for other combustion processes throughout the plant. These units may include boilers, reheat furnaces, annealing furnaces, process heaters, space heaters, and other miscellaneous direct- and indirect-fired combustion units, often in combination with natural gas or other purchased fuels. Coke oven gas and blast furnace gas used in this way reduces the amount of energy that would have to be purchased to operate these facilities and thereby reduces the CO_2 emissions that would be associated with those purchased fuels. In addition to combustion sources fired with coke oven gas or blast furnace gas, steel plants, whether integrated facilities or EAF facilities, contain numerous other combustion sources fired with natural gas or fuel oil. For larger plants, these sources can amount to hundreds of individual units. Subpart C of the proposed rule requires the reporting of CO_2 emissions for all such units, regardless of size or firing rates. In some cases this would require Tier 2 or Tier 3 methodology. For example, blast furnace gas-fired boilers and reheat furnaces at both integrated and EAF facilities typically exceed 250 MMBTUH. In other cases, Tier 1 methodology would be permitted. For combustion units larger than 250 MMBTUH, Tier 3 methodology is unnecessary. These combustion sources are not typically equipped with the instrumentation to comply with the prescribed methodology, and requirements to install such equipment are contrary to statements elsewhere in the rule that new monitoring equipment is not required. Accordingly, if reporting of all combustion source CO_2 emissions is retained in the final rule, we respectfully request that Tier 1 methodology apply. Total annual CO_2 emissions can be determined with sufficient certainty and accuracy by averaging routine fuel analyses or applying documented default values and estimated consumption rates.

Response: When two or more liquid-fired or gaseous-fired stationary combustion units at a facility combust the same type of fuel and the fuel is fed to the individual units through a common supply line or pipe, facilities may report the combined emissions from the units served by the common supply line, in lieu of separately reporting the GHG emissions from the individual units, provided that the total amount of fuel combusted by the units is accurately measured at the common pipe or supply line using a fuel flow meter that is calibrated in accordance with §98.34(a). If the common pipe option is selected, the applicable tier shall be used based on the maximum rated heat input capacity of the largest unit served by the common pipe configuration.

EPA has significantly expanded the use of the Tier 2 Calculation Methodology for units that combust only natural gas and/or distillate oil, in view of the homogeneous nature of these fuels. However, the Tier 3 methodology is still required for large 250 mmBtu/hr units that combust residual oil, solid fossil fuel, and other gaseous fuels (including coke oven gas and blast furnace gas).

For gaseous fuels other than natural gas and biogas, due to variability, the daily sampling requirement has been retained, but only for facilities with existing equipment in place that is capable of providing the data. Otherwise, weekly sampling is required. EPA also has limited the Tier 3 requirement to fuels that make up at least ten percent of the annual heat input for a unit or group of units.

The commenter should note that EPA has provided default values for coke oven gas and blast furnace gas in Table C-1, allowing units smaller than 250 mmBtu/hr combusting these fuels to use Tier 1 or Tier 2. EPA has also removed the cumulative 250 mmBtu/hr restriction on unit aggregation, and has clarified the common pipe reporting option.

Commenter Name: Filipa Rio
Commenter Affiliation: Alliance of Automobile Manufacturers (Alliance)
Document Control Number: EPA-HQ-OAR-2008-0508-0630.1
Comment Excerpt Number: 24

Comment: The Alliance supports the premise of a four-tier system of CO_2 emission calculation methodologies for stationary combustion. The tier concept provides for an appropriate level of monitoring and complexity based upon the significance of the source. In particular, Tier 1, which provides the use of a fuel-specific default CO_2 emission factor, a default heat content, and annual fuel consumption from company records, is particularly beneficial as opposed to a continuous monitoring approach (i.e., GEMS) that is costly and burdensome to smaller emitters.

Response: EPA appreciates your support, and thanks you for your comment.

Commenter Name: Keith Adams
Commenter Affiliation: Air Products and Chemicals, Inc.
Document Control Number: EPA-HQ-OAR-2008-0508-1142.1
Comment Excerpt Number: 23

Comment: The Preamble for the proposed rule states that CO_2 emissions far exceed the CO_2-e contributions of combustion byproduct emissions of CH_4 and N_2O, specifically "less than 1 percent of combined U.S. GHG emissions from stationary combustion, on a CO_2-e basis." Despite this insignificant contribution, combustion sources are being required to estimate these emissions. In some instances, particularly where the lower tier methods for calculating CO_2 emissions are employed, the calculation of combustion byproduct CH_4 and N_2O is straightforward. But in instances where more rigorous methods for calculating CO_2 emissions are required (e.g. Tier 4), the calculation of combustion byproduct CH_4 and N_2O requires a completely separate calculation process (and inherent process measurement data), comparable to Tiers 1 - 3 for CO_2 emissions. This is a burdensome requirement for an insignificant contribution to a source's overall GHG footprint. Air Products does not support calculating the combustion byproduct CH_4 and N_2O. However, if the agency feels these emissions are significant, it should allow greater use of Tiers 1, 2, and 3 for estimating CO_2 emissions (per comments on §98.33(b), above).

Response: See the Preamble, Section II. C., and the response to comment EPA-HQ-OAR-2008-0508-0561.1 excerpt 2 for information on the rationale for reporting for CH_4 and N_2O. EPA believes that the use of fuel-specific emission factors for these pollutants strikes an appropriate balance between minimizing the burden on reporters and obtaining valuable GHG emission data. EPA has, however, revised the final rule to exclude CH_4 and N_2O emissions from fuels for which the rule does not provide emission factors, and has deleted the provision allowing the owner or operator of a facility to develop site-specific emission factors for such fuels. EPA believes that this change will reduce the reporting burden on facilities.

The Agency has clarified the requirements to report under Tier 4, and has made several changes to reporting dates, extensions, and exceptions, that may indirectly address these concerns. While EPA does not find the methodologies for calculating CH_4 and N_2O emissions burdensome, EPA has clarified them in the final rule. When more than one type of fuel is combusted in a unit, direct measurements or engineering estimates of the annual heat input from each fuel are needed to calculate the CH_4 and N_2O emissions. Consequently, when CEMS (which are not fuel-specific) are used to monitor the CO_2 emissions and heat input for a multi-fuel unit, the total heat input measured by the CEMS must be apportioned to each fuel type. The owner or operator should use the best available information (e.g., fuel feed rates, GCV values, etc.) to do the necessary heat input apportionment.

Commenter Name: Keith A. Nagel
Commenter Affiliation: ArcelorMittal USA and Severstal North America
Document Control Number: EPA-HQ-OAR-2008-0508-0496.1
Comment Excerpt Number: 23

Comment: In lieu of the expensive testing for Tier 3, we are evaluating the potential to measure CO_2 emissions from the combustion of coke oven gas in an on-site gas chromatograph or other continuous monitoring device which could determine CO_2 emissions from a thermally oxidized sample. That approach would allow for direct measurement of the amount of CO_2 actually generated by combustion of the process gas. The resulting CO_2 generation factor could then be multiplied by the amount of coke oven gas combusted to generate total CO_2 emissions information. This direct combustion approach would be more accurate than the Proposed Rule's Tier 3 methodology because it would directly measure the actual amount of CO_2 generated when coke oven gas is combusted. In contrast, the Tier 3 approach would rely on a sampling estimate of the amount of carbon and the presumption that 100% of that carbon will become CO_2. The sample combustion approach under evaluation would also be more accurate because it would allow for sampling of the coke oven gas stream on a more frequent basis. That more frequent data would allow for adjustments based on the modest fluctuations that continuously occur in coke oven gas composition. This approach could be modeled on currently required TRS continuous monitors. Similar alternatives are potentially viable for blast furnace gas measurement. For example, steel plants may wish to use sampling data generated by the top gas analyzers and mass spectrometers located at each blast furnace. These analyzers measure CO_2 and CO very accurately in order to ensure efficient furnace operation. A simple formula that conservatively presumes the combustion of blast furnace gas will convert all CO to CO_2 could be used to reliably convert that data to projected CO_2 emissions with greater accuracy than available under Tier 3. To enable such improved methods, we request that the final rule authorize operators to develop and use any alternate emissions methodology that provides equal or greater accuracy than EPA's proposed approach.

Response: EPA's approach makes use of existing data and methodologies to the extent feasible, and is consistent with the types of methods contained in other GHG reporting programs (e.g., the California mandatory reporting rule, WCI, RGGI, TCR, and Climate Leaders). Because this approach specifies methods for each source category, it will result in data that are comparable across facilities. For consistency, EPA did not provide for alternative approaches as described by the commenter. However, the commenter should note that in the final rule EPA has permitted the use of chromatographic analysis to determine the carbon content and molecular weight of a fuel. EPA believes that the availability of this additional option will reduce the burden on reporters.

Commenter Name: Linda Farrington
Commenter Affiliation: Eli Lilly and Company (Lilly)
Document Control Number: EPA-HQ-OAR-2008-0508-0680.1
Comment Excerpt Number: 22

Comment: Lilly believes the use of fuel flow meters can generate a more accurate estimate of the CO_2 emissions than continuous emission monitoring, and they should be allowed for CO_2 estimation even if CEMS are present. If we look at the combustion device as a unit operation, the CO_2 emissions can be estimated from measurement of the output or input streams. The accuracy of the measurement devices on those inlet or outlet streams should drive that decision; outlet CEMS are not inherently superior to inlet fuel monitoring. In addition, to avoid missing data due to instrument or data collection downtime, the fuel flow meter is expected to provide a more accurate measurement of the total flow over a range of operating conditions. The outlet stack measurement depends on temperature, CO_2 concentration, and volumetric flow. Each of those has its own measurement uncertainty. The RATA performance specification requires that the CEMS measurement be within +/- 20% of the EPA's reference test method. [Footnote: 40 CFR 60, Appendix B, Performance Specification 6 — Specifications and Test Procedures for Continuous Emission Rate Monitoring Systems in Stationary Sources] By comparison, the fuel flow meters recently installed on a typical Lilly boiler have an accuracy estimated at +/- 2%. Affected facilities should have the flexibility to use instrumentation that provides more accuracy, reduced downtime, and reduced operating costs.

Response: See the response to comment EPA-HQ-OAR-2008-0508-0455.1 excerpt 7 and the response to comment EPA-HQ-OAR-2008-0508-0580 excerpt 10 for EPA's rationale and approach to the use of CEMS.

EPA has revised §98.33(b)(4)(ii) of the final rule to clarify that all six criteria specified in subparagraphs (A) through (F) must be met before Tier 4 is required. The Tier 4 CEMS requirement is limited to larger solid fossil fuel units with an existing pollutant CEMS or volumetric flow rate monitor, or a source with an existing CO_2 CEMS and flow rate monitor. EPA is requiring the use of CEMS due to the complexity of monitoring solid fuel consumption and the heterogeneous nature of the solid fuels. Units with fuel flow meters burning gaseous or liquid fuels are not required to use Tier 4.

Commenter Name: Keith Adams
Commenter Affiliation: Air Products and Chemicals, Inc.
Document Control Number: EPA-HQ-OAR-2008-0508-1142.1
Comment Excerpt Number: 22

Comment: The proposed rule imposes the Tier 4 calculation methodology on sources meeting the conditions specified under §98.33(b)(5)(ii). As worded, it appears any one of the (A), (B), (C), or (D) conditions would result in the Tier 4 method being required. This does not match the intent expressed in the Preamble to the proposed rule, and summarized in Preamble table C-1. In particular, Table C-1 appears to indicate that Tier 4 is required only for Solid Fossil Fuel fired units > 250 mmBTU/hr (meeting other criteria, as well) and that Gaseous Fossil Fuel fired and Liquid Fossil Fuel fired combustion units are required to use no more rigorous than Tier 3 methods. The current language of §98.33(b)(5)(ii) would imply any of the conditions described in §98.33(b)(5)(ii)(A), (B), (C) or (D) trigger the Tier 4 method requirement. We believe the agency's intent is that all of the conditions described in §98.33(b)(5)(ii)(A), (B), (C) and (D) are necessary in order to trigger the Tier 4 method requirement. §98.33(b)(5)(ii)(E) imposes the Tier 4 method if the source has any existing CEMS system. Depending on the type of gas monitoring system a source may have (extractive vs. in-situ; wet vs. dry, etc.) the addition of a CO_2 CEMS can be a very costly modification. Modifications could include, assuming it is even technically feasible, the addition of stack sampling ports, addition of extractive sampling systems, sample conditioning systems, calibration gas systems and modification to data acquisition and reporting systems and software. Based on our experience, these modifications can impose $40,000 to $250,000 of capital costs, as well as ongoing maintenance and operating costs for such units. These costs may be imposed on the false premise that direct emission measurement via CEMS is an inherently more accurate than alternative calculation methods (e.g. Tiers 1, 2, or 3). Clarify the requirement to employ the Tier 4 calculation method. Resolve the apparent discrepancy between the intent to limit Tier 4 to only Solid Fossil Fuel fired combustion units, per Table C-1 of the Preamble, with the actual imposition of Tier 4 described under §98.33(b)(5)(ii). Clarify that in order for Tier 4 to be required under §98.33(b)(5)(ii), all the conditions under §98.33(b)(5)(ii)(A), (B), (C), and (D) must be met. Specifically, conditions (A), (B), (C), and (D) should be separated by the word "and" – absent that, an implied "or" would force this calculation method on many other combustion units for which it was not intended. Do not require the use of the Tier 4 method where alternative fuel consumption data is available. Tier 1, 2, and 3 offer viable alternatives for many combustion sources that will yield comparable (and in many cases more) accurate emission estimates. Allow optional use of the Tier 4 method where, at the source's discretion. This may be a suitable calculation method where a source uses multiple fuels and/or non-commercial fuels or where existing CEMS systems include CO_2 measurement or can be modified at lower cost than alternative fuel consumption and/or characterization devices/practices. In any case, let the regulated source determine which method is most cost effective for their particular situation.

Response: EPA acknowledges the commenter's concerns regarding Tier 4 applicability. EPA has revised §98.33(b)(4)(ii) of the final rule to clarify that all six criteria specified in subparagraphs (A) through (F) must be met before Tier 4 is required. However, EPA disagrees with suggestions that Tier 4 should only be required if the installed CEMS include a CO_2 monitor. EPA is requiring the use of CEMS due to the complexity of monitoring solid fuel consumption and the heterogeneous nature of the solid fuels. Many of these fossil fuel-fired units with a pollutant CEMS have an existing diluent monitor (O_2 or CO_2) that can be used to determine CO_2 emissions. The incremental cost of adding a monitor to meet Tier 4 monitoring requirements is not unduly burdensome for a unit that is already required to install, certify, maintain, and operate a CEMS or flow rate monitor, and to perform ongoing QA testing of the existing monitors. EPA's estimates of monitoring costs are averages for a representative facility and may not represent the actual cost in individual circumstances.

Commenter Name: Keith Adams
Commenter Affiliation: Air Products and Chemicals, Inc.
Document Control Number: EPA-HQ-OAR-2008-0508-1142.1
Comment Excerpt Number: 21

Comment: The proposed rule defines the applicability of the alternate calculation method "tiers" based on combustion unit size and availability of data, with a general trend to require more rigorous calculation methods (e.g. increasing from Tier 1 to Tiers 2, 3, and 4) for higher operating capacity units and facilities that currently employ certain process or emission measurements. This push for more rigorous calculation methods is made without regard for a) the underlying accuracy of the calculation method, b) the quality and completeness of existing process or emission measurement, or the cost of the necessary measurement equipment or practice. The result is a rule that often requires a costly, laborious measurement/calculation method that does not improve the accuracy or completeness of the emission estimate. In many instances, less rigorous calculation methods (e.g. "lower" Tiers) will yield comparable (or better) accuracy emission estimates, with higher reliability and at lower cost. There is an implied assumption that directly measured emissions will yield a better emission estimate. This presumption is not true, as evidenced by an acceptable level of (in)accuracy tolerance under CEMS certification/calibration procedures (> 5-7%) versus levels of fuel consumption metering employed for invoice billing (typically < 2%). Air Products Comment: EPA should be more flexible as it relates to the applicability to the alternate combustion emission calculation methods. In particular: 1. Allow use of the Tier 1 method for units of any size (currently restricted to units < 250 mmBTU/hr or less), particularly for standard fuels of commerce such as natural gas, LP gas and fuel oils, where billing-quality consumption data is accurate and readily available and the default HHV and CO_2 emission factors are well known constants (as noted in the Preamble for the proposed rule – natural gas carbon content is always within 1% of the default ratio). 2. Recognize that a source's current practices of occasionally characterizing fuels for HHV or carbon content does not necessarily constitute having data "available" consistent with the compliance expectations of Tiers 2 and 3. Where Tiers 2 or 3 would be required, existing fuel characterization may not be according to the specified analytical methods or at the required frequency. Do not require Tier 2 or 3 where data fully meeting the defined compliance expectation is not currently being obtained. 3. Do not require the use of the Tier 4 method where alternative fuel consumption data is available; allow optional use of the Tier 4 method at the source's discretion. This may be a suitable calculation method where a source uses multiple fuels and/or non-commercial fuels or where existing CEMS systems include CO_2 measurement or can be modified at lower cost than alternative fuel consumption and/or characterization devices/practices. In any case, let the regulated source determine which method is most cost effective for their particular situation. This option is available in California's GHG mandatory reporting program.

Response: See the Preamble, Section II. L., on General Monitoring Requirements for the overall rationale for methodologies required under this rule, and the response to comment EPA-HQ-OAR-2008-0508-0909.1 excerpt 4 and EPA-HQ-OAR-2008-0508-0580 excerpt 10 for the rationale for methodologies required under Subpart C, and EPA-HQ-OAR-2008-0508-0695.1 excerpt 18 for additional information on rationale for CEMS.

EPA has, however, expanded the use of the Four Tier system to be more significantly more flexible. EPA has significantly expanded the use of the Tier 2 Calculation Methodology for units in which the only fossil fuels combusted are natural gas and/or distillate oil, in view of the homogeneous nature of these fuels. However, the Tier 3 methodology is still required for large 250 mmBtu/hr units that combust other fossil fuels.

EPA believes that it is clear in the final rule that a unit which otherwise qualifies to use Tier 1 will not be required to use Tier 2 unless the owner or operator routinely performs fuel sampling and analysis for the fuel high heat value, or routinely receives the results of HHV sampling and analysis from the fuel supplier at the minimum frequency specified in §98.34.

Additionally, units required have the flexibility in some circumstances to use company records and supplier information for obtaining HHV and fuel quantity.

EPA acknowledges the commenter's concerns regarding Tier 4 applicability. EPA has revised §98.33(b)(4)(ii) of the final rule to clarify that all six criteria specified in subparagraphs (A) through (F) must be met before Tier 4 is required. However, EPA disagrees with suggestions that Tier 4 should only be required if the installed CEMS include a CO_2 monitor, or not be required if alternative fuel records are available. EPA is requiring the use of CEMS due to the complexity of monitoring solid fuel consumption and the heterogeneous nature of the solid fuels. Many of these fossil fuel-fired units with a pollutant CEMS have an existing diluent monitor (O_2 or CO_2) that can be used to determine CO_2 emissions. The incremental cost of adding a to monitor meet Tier 4 monitoring requirements is not unduly burdensome for a large unit that combusts solid fossil fuels, and is already required to install, certify, maintain, and operate a CEMS or flow rate monitor, and to perform ongoing QA testing of the existing monitors.

Commenter Name: Leslie Bellas
Commenter Affiliation: National Lime Association (NLA)
Document Control Number: EPA-HQ-OAR-2008-0508-0520.1
Comment Excerpt Number: 20

Comment: Sources Should Be Permitted to Apply Different Tiers to Each Fuel Type Combusted in a Unit (40 C.F.R. §98.33(b)). 40 C.F.R. §98.33(b) indicates that units combusting multiple fuel types (e.g., burning coal and natural gas in the same kiln) could be required to use two different emission calculation methodologies (tiers) in order to calculate stationary fuel combustion. NLA requests confirmation of a statement made by EPA staff during a May 14 conference call that it is permissible to use multiple tiers for each fuel type combusted by a single unit.

Response: In response to comments, EPA has added language to the final rule to clarify the use of tiers. Section 98.33(b)(6) of the final rule explains that different tiers may be used for different fuels in the same unit, unless the use of Tier 4 is required or elected.

Commenter Name: Filipa Rio
Commenter Affiliation: Alliance of Automobile Manufacturers (Alliance)
Document Control Number: EPA-HQ-OAR-2008-0508-0630.1
Comment Excerpt Number: 19

Comment: The proposed four-tiered approach to estimating GHG emissions from fuel combustion units appears to provide appropriate emission calculation methodologies that serve a broad range of fuel combustion sources. The methodologies also appear consistent with many existing reporting programs. Additionally, the allowance of alternative reporting approaches for aggregating small combustion units, units sharing a common stack, or units served by a common supply line also serves to reduce the reporting burden while maintaining an equally high quality of data. The Alliance supports inclusion of these concepts in a final rule.

Response: EPA appreciates this comment, and believes that the final rule includes further clarification and flexibility regarding aggregation and common pipe provisions that will reduce the burden on sources. The cumulative 250 mmBtu/hr heat input capacity limit on the aggregation of units into a group has been dropped. Rather, the 250 mmBtu/hr restriction applies only to the individual units in the group. Therefore, for reporting purposes, individual units with maximum rated heat input capacities of 250 mmBtu/hr or less may be aggregated without limit into a single group, provided that the Tier 4 methodology is not required for any of the units, and all units in the group use the same tier for any common fuel(s) that they combust. Units with maximum rated heat inputs greater than 250 mmBtu/hr must report as individual units, unless they burn the same type of fuel (oil or gas) provided by a common pipe or supply line; case, the owner or operator may opt to use the common pipe reporting provisions in §98.36(c)(3). Units using Tier 4 must report as individual units unless they share a monitored common stack or duct; in that case, the common stack or duct reporting provisions of §98.36(c)(2) may be used.

Commenter Name: Leslie Bellas
Commenter Affiliation: National Lime Association (NLA)
Document Control Number: EPA-HQ-OAR-2008-0508-0520.1
Comment Excerpt Number: 18

Comment: The four-tier approach for calculating CO_2 combustion emissions is based on unit size and fuel type. The Proposed Rule should clarify how the maximum rated heat input capacity of a unit is determined and how tiers may apply to a single unit. Based on our review of 40 C.F.R. §98.3 3(b), use of the tiers is dependent, in part, on the maximum rated heat input capacity of a unit. 40 C.F.R. §98.6 provides that the "maximum rated heat input capacity" is determined as of the date of initial installation of the unit, as specified by the manufacturer. NLA requests confirmation that the maximum rated heat input capacity is equal to the original design and/or nameplate capacity of the unit so that the regulated community knows how the maximum rated heat input capacity is determined. If the maximum rated heat input capacity of the unit is the same as "design" or "nameplate" capacity of the unit, then NLA has no comment on the requirement in 40 C.F.R. §98.36(b)(3) to report that value to EPA. However, if sources are required to report the actual maximum rated heat input capacity of the kilns, NLA objects to providing that information because it provides information about the existing capability of the kilns to produce lime. NLA proposes that in accordance with 40 C.F.R. §98.37, any information regarding the actual maximum rated heat input capacity of the unit be retained in company records and made available for review upon request by EPA.

Response: EPA believes that the definition of "maximum rated heat input capacity" in §98.6 clarifies that this term refers to "the hourly heat input to a unit (in mmBtu/hr), when it combusts the maximum amount of fuel per hour that it is capable of combusting on a steady state basis, as of the initial installation of the unit, as specified by the manufacturer." This is consistent with the commenter's interpretation.

Commenter Name: Dan F. Hunter
Commenter Affiliation: ConocoPhillips Company
Document Control Number: EPA-HQ-OAR-2008-0508-0515.1
Comment Excerpt Number: 26

Comment: Table C-1: ConocoPhillips believes it would be useful and burden-reducing if EPA supplied an emission factor and default HHV for used oil combustion. Units that burn used oil, at least in the case of our Alaska operations, are very small and do not warrant the rigor of Tier 3 or 4 emission estimation methods.

Response: EPA has not provided default values for used oil in Table C-1 because the carbon content of used oil varies greatly and little data is available on which to support a credible default value. Had the commenter indicated published values then EPA would have been able to consider them for inclusion. However, the commenter should consult the revised Table C-1, as factors are provided for many other petroleum products, which may be applicable to used oil. Furthermore, EPA has revised the rule so that most units with a maximum rated heat input capacity less than 250 mmBtu/hr combusting fuels not listed in Table C-1 will not be required to report emissions from those fuels.

Commenter Name: Ram K. Singhal
Commenter Affiliation: Rubber Manufacturers Association (RMA)
Document Control Number: EPA-HQ-OAR-2008-0508-0600
Comment Excerpt Number: 15

Comment: As EPA's view is that emission factors for fuel combustion are far more accurate than direct measurements of GHGs exiting stacks as part of a combined train of exhausted emissions, we not only do not believe direct emissions measurements are necessary, but disagree that they are preferable. In addition, because of the cost and disruption caused by the installation and maintenance of emission measurements, or even performance testing on a regular basis, we think that the ambiguity in the proposal about when such methods will be required is unreasonable and profoundly unwise, particularly in comparison to how sound information on other pollutants is collected. We further object to the absence of a basis for calibration plans and for QA/QC plans for collecting GHG emissions data.

Response: See the response to comment EPA-HQ-OAR-2008-0508-0455.1 excerpt 7 and the response to comment EPA-HQ-OAR-2008-0508-0580 excerpt 10 for EPA's rationale and approach to the use of CEMS.

EPA does not have the view that emission factors for fuel combustion are far more accurate than direct measurements of GHGs existing the stacks.

EPA acknowledges the commenter's concerns about possible ambiguity regarding Tier 4 applicability. EPA has revised §98.33(b)(4)(ii) of the final rule to clarify that all six criteria specified in subparagraphs (A) through (F) must be met before Tier 4 is required.

EPA is requiring the use of CEMS due to the complexity of monitoring solid fuel consumption and the heterogeneous nature of the solid fuels. Many of these fossil fuel-fired units with a pollutant CEMS have an existing diluent monitor (O_2 or CO_2) that can be used to determine CO_2 emissions. The incremental cost of adding a monitor to meet Tier 4 monitoring requirements is not unduly burdensome for a large unit that combusts solid fossil fuels, and is already required to install, certify, maintain, and operate a CEMS or flow rate monitor, and to perform ongoing QA testing of the existing monitors.

See the Preamble, Section II. M., for the response on the general recordkeeping requirements.

EPA believes that the ongoing QA requirements for fuel flow meters are essential to ensure the quality of the emissions data reported and has specified these as part of the Monitoring Plan.

Commenter Name: Dan F. Hunter
Commenter Affiliation: ConocoPhillips Company
Document Control Number: EPA-HQ-OAR-2008-0508-0515.1
Comment Excerpt Number: 27

Comment: Table C-3: CH_4 and N_2O factors are not defined, but should be added, for the following fuel types currently listed in §98.38, Table C-1: 1. Ethane; 2. Biogas; 3. Isobutane; 4. n-Butane; 5. Natural Gasoline; 6. Other Oil (> 401 def. F); 7. Pentanes Plus; 8. Petrochemical Feedstocks; 9. Special Naphtha; and 10. Unfinished Oils.

Response: In response to the comment, EPA has extensively revised the default emission factors used to calculate CH_4 and N_2O emissions, adding generic fuel-based emission factors covering all fuels listed in Table C-1. For example, many of the fuels mentioned by the commenter are covered by the CH_4 and N_2O emission factors for "Petroleum" in Table C-2. EPA has clarified in the final rule that only CH_4 and N_2O emissions from combustion of those fuels listed in Table C-2 of Subpart C are required to be reported.

Commenter Name: Claire Olson
Commenter Affiliation: Basin Electric Power Cooperative
Document Control Number: EPA-HQ-OAR-2008-0508-0637.1
Comment Excerpt Number: 14

Comment: EPA has suggested frequent analysis for fuels, varying by the type of fuel. Since many of the facilities have consistent feedstocks, a full analysis of the feedstock or fuel on a daily basis creates an added expense that does not improve the accuracy of the reporting. Basin Electric urges EPA to allow flexibility to the facilities in the frequency and complexity of the fuel analysis that is commensurate with the variability of the feedstock and its relative impact on the accuracy of the GHG reporting. For example, with coal-fired facilities occasional ultimate analyses provides the information required for a full carbon balance, and this can be coupled with more frequent proximate analyses to provide assurance that the quality variation is within reasonable tolerance of what is considered typical fuel.

Response: The mandatory fuel sampling and analysis requirements for Tiers 2 and 3 have been considerably revised. §98.34 of the final rule requires that natural gas be sampled semiannually. For other fuels such as oil and coal, which are delivered in shipments or lots, requiring monthly sampling may be impractical. For fuel oil and coal, a representative sampling is required for each fuel lot, i.e., for each shipment or delivery. For other liquid fuels and biogas, quarterly sampling is required. For other solid fuels, excluding municipal solid waste, weekly composite sampling with monthly analysis is required. For other gaseous fuels, the daily sampling requirement has been retained, but only for facilities with existing equipment in place that is capable of providing the data. Otherwise, weekly sampling is required.

Commenter Name: See Table 10
Commenter Affiliation:
Document Control Number: EPA-HQ-OAR-2008-0508-0635
Comment Excerpt Number: 52

Comment: EPA's approach with regard to CH_4 and N_2O departs entirely from direct measurement. For these two gases, EPA instead proposes to use "EPA-provided default emission factors and annual heat input values" – which are generally among the least accurate emission calculation methods. We do not support this approach. While it is true that CH_4 and N_2O are relatively minor considerations in this source category, they should still be measured with a reasonable degree of accuracy. We recommend that EPA, at a minimum, require "periodic stack testing to derive site-specific emission factors for CH_4 and N_2O," as it suggests in the Preamble. Such testing, incorporated into improved emissions factors, will catch any surprisingly large emissions sources and will improve the accuracy of the monitoring system as a whole. Accurately characterizing N_2O emissions will be particularly important for fluidized bed coal plants. As EPA explains in AP-42: Formation of N_2O during the combustion process is governed by a complex series of reactions and its formation is dependent upon many factors. Formation of N_2O is minimized when combustion temperatures are kept high (above 1575 ^oF) and excess air is kept to a minimum (less than 1 percent). N_2O emissions for coal combustion are not significant except for fluidized bed combustion (FBC), where the emissions are typically two orders of magnitude higher than all other types of coal firing due to areas of low temperature combustion in the fuel bed. [FOOTNOTE: AP-42 at 1.1-5 – 1.1-6.] The National Coal Council has similarly explained: N_2O has a GWP 296 times that of CO_2. Because of its long lifetime (about 120 years) it can reach the upper atmosphere, depleting the concentration of stratospheric ozone, an important filter of UV radiation. N_2O is emitted from fluidized bed coal combustion; global emissions from FBC units are 0.2 Mt/year, representing approximately 2% of total known sources. N_2O emissions from [pulverized coal] units are much lower. Typical N_2O emissions from FBC units are in the range of 40-70 ppm (at 3% O_2). This is significant because at 60 ppm, the N_2O emission from the FBC is equivalent to 1.8% CO_2, an increase of about 15% in CO_2 emissions for an FBC boiler. Several techniques have been proposed to control N_2O emissions from FBC boilers, but additional research is necessary to develop economically and commercially attractive systems. [FOOTNOTE: 309 National Coal Council, Coal-Related Greenhouse Gas Management Issues (May 2003) at 7 (Ex 49)] In light of these unusually high emissions, we recommend that EPA require CEMS for plants of this type. If it does not, it should at least apply facility-specific emissions factors.

Response: See the response to comment EPA-HQ-OAR-2008-0508-0561.1 excerpt 2 for information on EPA's approach to CH_4 and N_2O emissions from stationary combustion. As stated in the proposed rule, in seeking a balance between accuracy of reporting information, burden to reporters, and size of emissions source, EPA decided that the direct measurement option (CEMS or source test to develop source specific emission factors) was too costly for the small improvements in data quality that it might achieve. The CH_4 and N_2O emissions from stationary combustion are relatively low compared to the CO_2 emissions. EPA believes using fuel-specific default emission factors to calculate CH_4 and N_2O emissions is in accordance with methods used in other programs and provides data of sufficient accuracy.

EPA disagrees that CEMS should be required. As in the proposed rule, a CEMS methodology was not selected for measuring N_2O primarily because the cost impacts of requiring the installation of CEMS is high in comparison to the relatively low amount of N_2O emissions (even on a CO_2e basis) that would be emitted from stationary combustion equipment.

Commenter Name: Rich Raiders
Commenter Affiliation: Arkema Inc.
Document Control Number: EPA-HQ-OAR-2008-0508-0511.1
Comment Excerpt Number: 51

Comment: Arkema operates a material recovery operation at one facility where the facility uses an alumina regeneration system to condition process fluids and roasts the spent alumina onsite for recycling. This natural gas combustion activity would be included in Subpart C applicability, but the process is not included in any other Part 98 subpart. The alumina is placed into the roaster system as a solid exhibiting an organic coating. As the alumina progresses through the heated rotating drum system, the organic materials evolve from the alumina, so that when the alumina is clean when removed from the roaster system. As a consequence of roasting, organic materials on the alumina surface are evolved from the alumina, where some of the materials may coincidentally combust as the alumina is heated at or near the autoignition temperature of some of the constituents. The natural gas combustion vent and roasting vent are discharged through separate vent systems. The CO_2 generation from the organic evolution phase of the roasting process represents a small fraction of the total roasting CO_2 emissions, far less than the comparable fuels-based minimum heat input value described above. EPA does not include any case-by-case determination method for Subpart C reporters to determine or calculate GHG emissions from this type of activity, or exclude consideration of the secondary material's minimal fuel value that does not contribute significant heat value to the underlying combustion activity. EPA should provide a calculation method where the reporter could measure the total organic content of a material being roasted, determine if the material contributes significant heat value per the comparable fuel definition, calculate GHG emissions from material evolution if required, add any GHG emissions to the total fuel combustion emissions reported under Subpart C if necessary, and file any annual reporting for the stream. Arkema is concerned that a GHG reporting rule could, because of the difficulties in complying with the proposed Part 98, cause the company to dispose of several tons of solid waste per week, rather than manage the insignificant amounts of GHG emissions evolving from the roasting alumina. The only compliance option that might be feasible in the current Subpart C would be placing the natural gas portion of the roaster, from where most of the GHGs are emitted, into a Tier 1 or 2 system, and the roaster process exhaust system, where very little GHG are actually emitted, into Tier 4 where a continuous emission monitor ("CEM") system would be required. Were Arkema forced to cease roasting as an economic decision for Part 98 compliance, the solid waste disposal costs and associated burden with unnecessarily consuming natural resources that are better left in a recycling system should be part of EPA's cost considerations. EPA could not have intended for facilities roasting materials for recycling to cease recycling activities and/or investing in CEM systems for trivial GHG emission streams. Arkema has advocated in several portions of this comment document for a case-by-case determination system to address unusual situations like this, where the facility can propose a compliance option that balances the EPA need for reasonably accurate GHG emissions data and the cost of compliance for each individual process.

Response: EPA has added language to §98.33 clarifying and revising the use of the four tiers. It is not EPA's intent to require Tier 4 methods to calculate emissions from this type of process.

Tier 4 is only required when the unit meets all of the criteria listed in §98.33(b)(4)(ii) or (iii). Tier 3 is only required to calculate emissions for a fuel for which emission factors are not provided when Tier 4 is not required, the fuel is not exempted from reporting in §98.30, and the unconventional fuels provide, on average, at least ten percent of the annual heat input to an individual unit with a maximum rated heat input capacity greater than 250 mmBtu/hr or group of units served by a common supply pipe. Most units with a maximum rated heat input capacity less than 250 mmBtu/hr may report using Tier 1 or Tier 2, and according to the final rule will not be required to report emissions from fuels for which default values are not provided. Therefore, in this case it appears that only the emissions from the combustion of natural gas in the unit would need to be reported because there are no default emission factors for organic materials on the alumina surface.

Commenter Name: Rich Raiders
Commenter Affiliation: Arkema Inc.
Document Control Number: EPA-HQ-OAR-2008-0508-0511.1
Comment Excerpt Number: 49

Comment: Thermal oxidizers are used to control emissions of a variety of processes, dispose of non-hazardous wastes, pre-heat process fluids, and heat or boil water. These devices combust a variety of materials, but typically burn natural gas as the primary or pilot fuel. Facilities operating thermal oxidizers are normally required to document the amount of material routed to the device, the device destruction efficiency, and the amount of fuel used in the device. In the proposed Subpart C, thermal oxidizers seem to fall into the Tier 3 requirements, where operators are required to measure heat input, molecular weight, and carbon content on a daily basis. Many thermal oxidizer systems are installed on existing systems that were retrofitted from designs which are years or decades old. As such, many of these systems are not designed with any valid location to measure the parameters required by the proposed Tier 3 requirements. For example, one Arkema thermal oxidizer system collects vapors from three separate headers that are only combined at the thermal oxidizer. EPA has published existing standards for appropriate sampling and measurement locations (40 CFR 60, Appendix A, Method 1) that cannot be achieved in many thermal oxidizer systems without the operator incurring millions in dollars to retrofit the device to accommodate instrument sampling. Although Arkema cannot provide an industry-wide estimate of how many combustion devices would not readily accommodate appropriate stream sampling, the company suggests that many similar devices, where the only required parametric monitoring consists of firebox temperature monitoring, exist in the field that would require expensive retrofits to obtain valid heat value, carbon content, and molecular weight determinations. EPA should provide a Tier 3 alternate allowing facilities that can calculate the appropriate Tier 3 parameters in lieu of sampling when the facility has the ability to calculate combustion device loadings. This option should only be required when the heat load from the thermal oxidizer load meets the comparable fuels minimum heat input contribution described above. EPA should allow facilities required to comply with existing CAA provisions that require combustion device inlet loading determinations to calculate combustion device loadings on a periodic basis. Another complication concerning carbon content and molecular weight measurement is that many compounds routed to many emission control devices are not properly measured by the same instrument set. EPA has published regulations that require that monitoring instruments that measure organic chemical concentrations must be able to detect the organic compounds being measured within an order of magnitude of standard instrument concentrations, or the complying facility must change instruments to provide an instrument that can adequately quantify the stream in question. This situation often emerges in vent streams containing halogens (fluorine, chlorine, bromine, iodide), sulfur, nitrogen, and other similar anions. Arkema operates systems where two gas chromatograph systems are required to measure various organic compounds within a single facility to accommodate the different molecules that must be measured to demonstrate compliance. Facilities operating control devices, where the waste gas stream contributes significant heat value that can calculate combustion device loadings without use of instruments should be provided a calculated combustion device loading in proposed Subpart C. The heating value calculations, which already exist in Title V permit basis calculations, would allow facilities that would need to expend significant funds retrofitting existing ductwork configurations to avoid unnecessary expenditures that do not increase reporting accuracy.

Response: See the Preamble, Section III. C., for the response on the definition of the source category.

EPA has revised §98.33 to deal with certain unconventional combustion processes and types of fuel. In the Preamble, EPA has explained that "devices such as thermal oxidizers and pollution control devices . . . would report only the GHG emissions from the firing of supplemental fossil fuels." EPA believes that these provisions satisfy the intent of Part 98, to collect accurate and consistent GHG emissions data that can be used to inform future decisions.

Commenter Name: Gregory A. Wilkins
Commenter Affiliation: Marathon Oil Corporation
Document Control Number: EPA-HQ-OAR-2008-0508-0712.1
Comment Excerpt Number: 48

Comment: Marathon supports not requiring stack test data to derive site specific emission factors for CH_4 and N_2O emissions. EPA considered this approach to estimate CH_4 and N_2O emissions. This would have been costly with little benefit. Marathon supports the use of fuel-specific default emission factors if these emissions are not excluded entirely.

Response: EPA appreciates the supportive feedback, and has maintained these specifications in the final rule. EPA has also revised the rule so that only CH_4 and N_2O emissions from those fuels listed in Table C-2 of Subpart C are required to be reported.

Commenter Name: Gregory A. Wilkins
Commenter Affiliation: Marathon Oil Corporation
Document Control Number: EPA-HQ-OAR-2008-0508-0712.1
Comment Excerpt Number: 47

Comment: Marathon opposes the sampling requirements under the Tier 3 methodology. Marathon would be forced into this tier for refinery fuel gas combustion because there is no emission factor for refinery fuel gas given by EPA. This tier would require daily sampling of carbon content of the fuel gas. Marathon proposes that EPA allow the option of using an industry derived emission factor or a facility specific derived emission factor if it is determined that fuel gas samples are consistent over a period of time. If mandatory sampling is required, Marathon proposes that the sampling frequency is lessened as the fuel gas characteristics have limited variability. For this frequency, Marathon proposes monthly or weekly sampling of fuel gas. These requirements would reduce burden and cost on collecting the samples, the associated QA/QC, and the current reporting requirements while still giving accurate estimation of emissions. It is not cost effective for the benefit received to require daily sampling of refinery fuel gas.

Response: EPA believes that the Tier 3 methodology is appropriate for units larger than 250 mmBtu/hr combusting refinery gas, due to its potential variability. For gaseous fuels other than natural gas or biogas, the daily sampling requirement has been retained, but only for facilities with existing equipment in place that is capable of providing the data. Otherwise, weekly sampling is required. The commenter should note that EPA has provided a default emission factor and HHV for refinery gas, which will allow smaller sources combusting refinery gas to use Tier 1 or Tier 2.

Commenter Name: Gregory A. Wilkins
Commenter Affiliation: Marathon Oil Corporation
Document Control Number: EPA-HQ-OAR-2008-0508-0712.1
Comment Excerpt Number: 46

Comment: Marathon interprets that the use of Tier 4 methodology (use of CEMs) only apply to large stationary combustion units that are fired with solid fuels and that have existing CEMs. Tier 4 methodology is not and should not be required if a facility has a CEM but does not combust solid fossil fuel or does not have a CO, monitor on the CEM. Additionally, the Preamble states that an upgrade would be required if a CO_2 monitor or an O_2 monitor was not present or if a flow meter was not installed. Marathon interprets this to mean that these upgrades would only be required for the CEMs if solid fossil fuel was being combusted. Also, Marathon interprets the Preamble language on page74 FR 16483 to mean that CEMs currently installed would not be required to monitor other types of fuel (besides solid fossil fuel) combusted but could be used if chosen by the facility. If a facility has a CEM but does not combust solid fossil fuel and does not have a CO_2 monitor on the CEM, they should not be required to install a CO_2 monitor and use Tier 4 reporting. Marathon requests that this clarification be made in section 98.33(b)(5) by adding "and" after each defining statement for Tier 4 use.
Response: EPA acknowledges the commenter's concerns regarding Tier 4 applicability. EPA has revised §98.33(b)(4)(ii) of the final rule to clarify that all six criteria specified in subparagraphs (A) through (F) must be met before Tier 4 is required. Therefore a source that does not burn a solid fuel is not required to meet Tier 4.

Commenter Name: Rich Raiders
Commenter Affiliation: Arkema Inc.
Document Control Number: EPA-HQ-OAR-2008-0508-0511.1
Comment Excerpt Number: 43

Comment: EPA should also encourage facilities to not modify combustion units to adjust the balance between CO_2 and carbon monoxide ("CO"), or the balance between CO_2 and oxides of nitrogen ("NO_x") in individual combustion units subject to Subpart C. Although GHG reporting may identify combustion improvement opportunities at some locations, Part 98 should not be used to cause facilities to modify combustion practices that are tuned to comply with other CAA regulatory requirements.

Response: In response to the comment, EPA does not believe that any additional language is needed to encourage facilities not to modify their combustion practices. Because the rule focuses solely on reporting GHG emissions, it is not appropriate for it to comment on GHG reduction strategies.

Commenter Name: Rich Raiders
Commenter Affiliation: Arkema Inc.
Document Control Number: EPA-HQ-OAR-2008-0508-0511.1
Comment Excerpt Number: 42

Comment: At least one Arkema facility uses combined gas metering to track combusted pipeline fuel entering several similar combustion systems, including one system using pressure swing adsorption ("PSA") to remove the non-methane fraction from pipeline natural gas. EPA should allow facilities using centralized pipeline fuel metering systems, but distributing the fuel to a number of combustion devices, to report GHG emissions based on the combined stream. Further, facilities should be allowed to use process knowledge and design specifications to determine the heating value and composition of the pipeline-origin commodity fuels, rather than requiring fuel composition determination on each stream reaching each individual combustion device.

Response: Under the proposed and revised rule, a facility may calculate GHG emissions for a group of units (rather than unit-by-unit emissions) when the same liquid or gaseous fuel is used by each unit and is fed by a metered common pipe (e.g., a natural gas meter at the facility gate). See the common pipe reporting provisions in §98.36. This flexibility is consistent with existing protocols and methodologies allowed by EPA in existing programs.

EPA has made changes to the proposed rule to clarify that fuel sampling and analysis data provided by the supplier may be used in the emission calculations as an alternative to determining heating value and composition, and that fuel billing meters may be used to quantify fuel consumption. EPA did not include the commenter's suggestion to allow process knowledge and design specifications to determine heating value and composition of pipeline-origin commodity fuels because this information would be very difficult to verify and is not expected to be any more accurate than the alternatives provided. However, EPA has expanded the use of Tier 2 Calculation Methodology to units of any size combusting only distillate oil and/or natural gas. EPA has revised the pipeline natural gas sampling frequency to require that natural gas be sampled semiannually.

Commenter Name: Fiji George
Commenter Affiliation: El Paso Corporation
Document Control Number: EPA-HQ-OAR-2008-0508-0398.1
Comment Excerpt Number: 40

Comment: El Paso recommends allowing alternate Tier 2 calculations for homogeneous gaseous fuels such as pipeline quality natural gas. The alternate Tier 2 would allow using fuel carbon content instead of high heating value. For majority of natural gas transmission facilities, the high heating value of the transported gas is not directly measured but rather calculated based on gas composition. Therefore, our facilities can easily implement CO_2 emission calculations based on carbon content. However, it is recommended that annual average carbon content could be used in lieu of monthly fuel and carbon content data as explained above in order to minimize reporting burden. This request is consistent with EPA's programmatic goals outlined in the Preamble related to consistency with existing reporting programs and minimizing reporting burden.

Response: The IPCC and the "Inventory of U.S. Greenhouse Gases and Sinks" do not use carbon contents of mass or volume of fossil fuels rather than HHV because carbon content typically varies less per HHV than it does for a given mass or volume. EPA has followed this approach in Part 98. However, the commenter could use gas composition data to determine both HHV and carbon content per unit HHV.

EPA has expanded the use of the Tier 2 Calculation Methodology to include units greater than 250 mmBtu/hr that combust only pipeline natural gas and/or distillate oil. However, these units still have the option of using Tier 3 calculations, based on measured carbon content.

The mandatory fuel sampling and analysis requirements for Tiers 2 and 3 have been considerably revised. Section 98.34 of the final rule requires that natural gas be sampled semiannually.

Commenter Name: Kelly R. Carmichael
Commenter Affiliation: NiSource
Document Control Number: EPA-HQ-OAR-2008-0508-1080.2
Comment Excerpt Number: 12

Comment: NiSource supports EPA's decision to not require CEMS methodology for measuring CH_4 and N_2O emissions from Stationary Fuel Combustion Sources and, therefore, not requiring installation of CEMS for that purpose. NiSource agrees with EPA that this option is too costly for the small improvement in data quality that may be achieved instead of using the proposed approach of using fuel-specific default emission factors.

Response: EPA appreciates the supportive feedback, and has maintained these specifications in the final rule. EPA has also revised the rule so that only CH_4 and N_2O emissions from those fuels listed in Table C-2 of Subpart C are required to be reported.

Commenter Name: Michael DiMauro
Commenter Affiliation: Massachusetts Municipal Wholesale Electric Company (MMWEC)
Document Control Number: EPA-HQ-OAR-2008-0508-0580
Comment Excerpt Number: 16

Comment: For Units with a design heat input < 250 MMBtu/hr the Proposed Rule does not allow use of Tier I monitoring procedures and calculation methods if fuel sampling and analysis to determine the fuel high heat content is currently being performed on a monthly or more frequent basis either on-site or by the supplier – see 98.33(b)(1). Such sources must conform with Tier II monitoring procedures and calculation methods. For many dual (oil/gas) fuel units, high heat (Btu/scf) values for natural gas are provided by the fuel supplier on a monthly basis, but high heat (Btu/gal or Btu/lb) values for oil are only provided with each fuel shipment, and such deliveries can occur much less frequently than monthly depending on the size of on-site oil tanks and the frequency of oil firing. 1. The GHG Reporting rule should allow dual fuel units to monitor CO_2 emissions generated by each fuel type using different Tier schemes, if applicable. It should not be required that the same Tier monitoring method (i.e. I or II) be used for all fuel types fired by a stationary combustion unit. 2. The rule should clarify how to determine whether the Tier II methodology is applicable to oil, for a dual fuel unit that receives oil deliveries occasionally at non-periodic intervals (i.e. during some months, multiple deliveries may occur, in other months no oil deliveries may occur). It is suggested that if sources that receive oil high heat values from the fuel supplier with each oil shipment (delivery) are required to conform with the Tier II methodology, then such units should be allowed to use fuel supplier values alone (with no supplemental on-site sampling), even if the fuel supplier analysis data is received less frequently than monthly.

Response: In response to comments, EPA has added language to the final rule to clarify the use of tiers. Section 98.33(b)(6) of the final rule explains that different tiers may be used for different fuels in the same unit, unless the use of Tier 4 is required or elected. Furthermore, in response to comments, EPA has added flexibility to the use of the four tiers. In the final rule, Tier 2 may be used to calculate emissions from a unit of any size that only combusts distillate fuel oil and/or pipeline quality natural gas. EPA has also considerably revised the minimum sampling frequencies that trigger, and are required for Tier 2. In the final rule, for example, Tier 2 is to be used for natural gas if it is sampled and analyzed semiannually, or more frequently, and for fuel oil if at least one representative sample from each lot is analyzed. Furthermore, EPA has clarified in the final rule that analysis data from fuel suppliers may be used in emissions calculations. In this case it appears that Tier 2 would be used to calculate emissions from both fuels combusted in the oil/gas unit.

Commenter Name: J. P. Blackford
Commenter Affiliation: American Public Power Association (APPA)
Document Control Number: EPA-HQ-OAR-2008-0508-0661.1
Comment Excerpt Number: 2

Comment: APPA requests that EPA clarify the criteria that must be met for a utility to be required to report its GHG emissions from electric generation using Tier 4 methodology (§98.33(b)(5)(ii)). APPA is concerned that the proposed rule does not specify that all of the criteria must be met in order for a utility to be required to report using Tier 4 methodology. APPA believes that EPA intended this to be the case since in the "Information Sheet" for Subpart C — General Stationary Fuel Combustion Sources has a flow chart on page 3 which implies that all the conditions must be met. APPA requests that EPA specifically state that a utility must meet all the conditions to be required to report under Tier 4 methodology, otherwise, they are permitted to report under Tier 3 or lower, as appropriate. If this is not specifically stated and future interpretation mandates that units that operate in excess of 1,000 hours and combust solid fuel install CEMS, it will pose a significant challenge for APPA utility members. Some APPA member utilities operate coal-fired units that are not required to install CEMS. These are generally smaller units (on the order of 25 MW); therefore, the capital cost as well as the operational cost of these CEMS for units of this size would be prohibitive. These costs would have to be passed on to the community at a time when communities and its residents can least afford them. The slight increase in accuracy gained by using CEMS as opposed to Tier 3 methodology would not justify the expenditures the utility would be required to make.

Response: EPA acknowledges the commenter's concerns regarding Tier 4 applicability. EPA has revised §98.33(b)(4)(ii) of the final rule to clarify that all six criteria specified in subparagraphs (A) through (F) must be met before Tier 4 is required.

Commenter Name: Lawrence W. Kavanagh
Commenter Affiliation: American Iron and Steel Institute (AISI)
Document Control Number: EPA-HQ-OAR-2008-0508-0695.1
Comment Excerpt Number: 13

Comment: Stove stacks are not typically equipped with the instrumentation necessary to comply with Tier 3 methodology, and requirements to install such equipment are in conflict with statements elsewhere in the rule that new monitoring equipment is not required. Moreover, requirements for efficient and productive operation of blast furnaces dictate a very stable operation, including stove heating practices. This means that the chemistry and heating value of blast furnace gas and the resulting products of combustion at any given facility will be fairly consistent over time. Accordingly, if reporting of blast furnace stove stack CO_2 emissions is retained in the final rule, we respectfully request that Tier 1 methodology apply. Total annual CO_2 emissions can be determined with sufficient certainty and accuracy by averaging routine blast furnace gas carbon analyses or documented default values and estimated consumption rates. Reporting of emissions associated with blast furnace stoves and blast furnace gas-fired boilers, whether under Tier 1 or Tier 2, necessitates the addition of a blast furnace gas default value in Table C-1 or C-2.

Response: See the Iron and Steel source category section of the Preamble and the source category comment response document.

The commenter should note that EPA has added emission factors to Table C-1 for both blast furnace gas and coke oven gas. This will reduce the burden on sources by allowing units smaller than 250 mmBtu/hr combusting these fuels to use Tier 1 or Tier 2. However, units larger than 250 mmBtu/hr combusting these fuels will be required to report using Tier 3, due to the fuels' potential variability and the the size of the unit which makes it potentially larger source of emissions. The commenter should note that the fuel sampling requirements have been reduced to weekly for units combusting alternative gaseous fuels which do not have the equipment in place for daily sampling.

Commenter Name: J. P. Blackford
Commenter Affiliation: American Public Power Association (APPA)
Document Control Number: EPA-HQ-OAR-2008-0508-0661.1
Comment Excerpt Number: 12

Comment: Methane (CH_4) and nitrous oxide (N_2O) make up a very small portion of total GHG emissions from the combustion of fossil fuels. APPA supports simplified methodology for calculating these emissions as the opportunity to enhance the accuracy of the total GHG emissions in aggregate would not justify the additional effort required.

Response: EPA appreciates the supportive feedback, and has maintained these specifications in the final rule. EPA has also revised the rule so that only CH_4 and N_2O emissions from those fuels listed in Table C-2 of Subpart C are required to be reported.

Commenter Name: Lawrence W. Kavanagh
Commenter Affiliation: American Iron and Steel Institute (AISI)
Document Control Number: EPA-HQ-OAR-2008-0508-0695.1
Comment Excerpt Number: 12

Comment: The proposed rule requires the reporting of CO_2 emissions from blast furnace stoves under Subpart C. Blast furnace stoves are refractory-lined chambers that serve as heat exchangers to heat the incoming blast air. The source of heat is the off-gas from the blast furnace, which typically has a heating value of about 90 BTU/cubic foot. The blast furnace gas contains both CO_2 and CO, that when burned emits CO_2. The original source of carbon in the blast furnace gas is coke or other carbon-bearing fuels (e.g., natural gas, oil, or pulverized coal) or raw materials (limestone, dolomite) that combine with the oxides in the iron ore or pellets. About 25% of the blast furnace gas is used in the stoves, and CO_2 is emitted as a product of combustion from the stove stacks. (The remainder of blast furnace gas is typically used as a boiler fuel to provide steam to drive the blast air turbines or to provide steam or electricity for use elsewhere in the plant.) Because the amount of blast furnace gas consumed in stoves would typically exceed 250 MMBTUH, Subpart C would require the use of Tier 2 or Tier 3 calculation methodology. With respect to potential applicability of Tier 4 to blast furnace stove, see our comments for coke oven combustion stacks regarding necessary clarifications to §98.33(b)(5).

The CO_2 emissions associated with combustion of blast furnace gas are already accounted for under reporting requirements of fuel suppliers. Although part of the CO and CO_2 in blast furnace gas could be attributed to limestone or dolomite fluxes, it is impossible to discern the relative contribution of carbon contained blast furnace gas from coke or other reducing agents versus that contained in the fluxes. Tier 2 relies on monthly measured heat values and default emission factors (from Tables C-1 or C-2), and the quantity of fuel combusted based on company records. Tier 3 requires the use of monthly measurements for fuel carbon content, molecular weight, and fuel quantities. However, we believe that both of these requirements are unnecessary and believe that Tier 1 (based on annual emissions and default emission factors) is an acceptable calculation methodology for the following reasons.

Response: See the Iron and Steel source category section of the Preamble and the source category comment response document.

See the Preamble, Section II., for a discussion of upstream and downstream reporting.

The commenter should note that EPA has added emission factors to Table C-1 for both blast furnace gas and coke oven gas. This will reduce the burden on sources by allowing units smaller than 250 mmBtu/hr combusting these fuels to use Tier 1 or Tier 2. However, units larger than 250 mmBtu/hr combusting these fuels will be required to report using Tier 3, due to the fuels' potential variability and the the size of the unit which makes it potentially larger source of emissions. The commenter should note that the fuel sampling requirements have been reduced to weekly for units combusting alternative gaseous fuels which do not have the equipment in place for daily sampling.

Commenter Name: Rhea Hale
Commenter Affiliation: American Forest & Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2008-0508-0909.1
Comment Excerpt Number: 11

Comment: If EPA insists that CEMs are required, then it should provide clarification regarding under which standards they are to be operated. The rule is unclear as to whether Part 75, Part 60 or state requirements are to be followed. In certain areas it appears that facilities are allowed to choose which provisions to follow and in others it does not.

Response: EPA agrees that the proposed language could be confusing, and has added language to the final rule to clarify that any one of the alternate initial certification procedures for CO_2 CEMS is acceptable. EPA has also clarified that the requirements of Part 75, Part 60, or an applicable State continuous monitoring program are equally applicable for ongoing quality assurance.

Commenter Name: Jeffry C. Muffat
Commenter Affiliation: 3M Company
Document Control Number: EPA-HQ-OAR-2008-0508-0793.1
Comment Excerpt Number: 11

Comment: 3M owns and operates a hazardous waste incinerator used to manage its various waste streams. We will not be able to use either Tier 1 or Tier 2 calculation methodologies listed in Subpart C because there are no default values for their "fuel" in Tables C-1 and C-2. The Tier 3 calculation methodology provides an onerous calculation option which requires each waste stream to be tested or estimated for carbon content. For the 3M-owned hazardous waste incinerator this would equate to thousands of waste streams. Such testing or estimation work is not a standard part of typical operations and should not be required as a part of a reporting rule. Tier 4 requires use of CO_2 CEM data. Most hazardous waste incinerators, including the hazardous waste incinerator owned by 3M, do not have CO_2 monitors currently installed. We are concerned that carbon dioxide monitors will not be available for all who need to purchase such devices. Even if they can be purchased, it will take time to install, calibrate and ensure the operation of such devices. We will need more than the 2-3 months contemplated by the effective date of the proposed rule to accomplish such tasks. To address this problem, 3M has two suggestions. The first one is to require reporting only from those facilities that have a default emissions factor in either Tables C-1 or C-2. This would cover most of the major combustion sources while not subjecting the minor sources to extensive testing requirements. The second suggestion is to add a Tier 5 to Subpart C so facilities have an option to develop site-specific emissions factors. Adding the ability to do this would give these facilities another tool to allow for accurate estimates of carbon dioxide emissions.

Response: EPA has revised §98.30 to specify that units that combust hazardous waste will not be required to report GHG emissions unless CEMS are used or another fuel for which default factors are provided is also combusted in the unit. Only emissions from supplemental fuels need to be reported.

Commenter Name: Keith Overcash
Commenter Affiliation: North Carolina Division of Air Quality (NCDAQ)
Document Control Number: EPA-HQ-OAR-2008-0508-0588
Comment Excerpt Number: 10

Comment: Comments on the combustion methodology: 1. It is widely recognized that the emission factors for methane and nitrous oxide from stationary source combustion depend on both the fuel and the technology type. EPA's calculation approach utilizing simplified technology-independent factors is contrary to the current methodology used by the World Resources Institute, The Climate Registry, and guidance from the Intergovernmental Panel on Climate Change. Different technologies for coal combustion, such as bituminous fluidized bed combustors, have significantly higher N_2O emission factors; due to the large global warming potential of this GHG, this can make a significant difference in total GHG emissions for some facilities. NC DAQ believes that EPA should be consistent in its calculation methods with these organizations; it is more technically correct and will reduce the burden of reporting via different methods. 2. EPA should develop and provide as part of the rule default heat content and CO_2,

CH_4 and N_2O emission factors for additional fuels. EPA provides CO_2 emission factors for additional fuels in Table C-2; however, not all fuels in that table have corresponding CH_4 or N_2O factors in Table C-3. Does this mean that sources emitting these will need to develop site-specific factors based on the results of source testing? We are particularly concerned that sources meeting the threshold and burning small quantities of fuels not addressed in the EPA's Emission Factor tables will be required to spend resources on testing these fuels. This issue may also be addressed by utilizing a de minimis level (see comment 14); nonetheless we still recommend that EPA add information that would allow emissions to be computed for additional fuels. In addition, the "solvent" fuel (Table C-2) should be described in more detail. In particular, does "solvent" fuel represent the VOC being combusted in a thermal oxidizer? Facilities that combust rendered animal fat, a fuel used commonly in NC food processing industries, are likely to be subject to reporting requirements; this fuel should be added to the emission factor tables. NC has recommended emission factors for this fuel in its guidance document on combustion: http://daq.state.nc.us/monitor/eminv/forms/StationaryCombustion Sources.pdf. The recommendation is to treat animal fat as "waste oil." NC provides an input-based emission factor calculated as 9.2 kg CO_2/gal based on heating value of 124,586 Bt/gal. This value is based on a source test found in a permit (reference available in above pdf document).3. EPA should provide a calculation methodology for thermal oxidizers used for controlling VOC emissions. There are two sources of GHG emissions for this process: 1) emissions resulting from combustion of the fuel added to the oxidizer (e.g., natural gas or oil that may be needed to allow the oxidizer to reach the combustion temperatures required to destroy the VOC) and 2) emissions resulting from the combustion of the VOC. If the rule does intend to cover emissions resulting from the VOC portion of the emissions (which it appears to do, since that process fits under the combustion definition), then there should be simplified approaches provided to compute emissions; otherwise this source should be exempted.
4. While we recognize the benefits of direct measurements, we also recognize that the degree of fluctuation of fuel characteristics does not justify the cost of fuel sampling. EPA should provide flexibility to facilities in being able to use supplier data to characterize the fuel characteristics used in computing emissions or reduce fuel sampling frequency if the variability in fuel quality is determined to be insignificant.

Response: See the Preamble, Section II. C., and the response to comment EPA-HQ-OAR-2008-0508-0561.1 excerpt 2 for information on the rationale for reporting for CH_4 and N_2O.

EPA's approach to CH_4 and N_2O emission factors is consistent with the IPCC Guidelines in that default emission factors are appropriate for sources that are not considered key sources. Technologically dependent emission factors for N_2O are used at the national level for mobile sources because of the significantly larger contribution of these sources than stationary sources. The default emissions factors used in this rule come from the IPCC Guidelines and were established on the basis of measurement sampling from stationary sources, and do reflect broadly combustion conditions across a variety of conditions. The use of fuel-specific emission factors is in accordance with methods used in other programs and provides data of sufficient accuracy, given the small amount of emissions, for the purposes of this rule.

EPA has also extensively revised the default emission factors used to calculate CH_4 and N_2O emissions, adding generic fuel-based emission factors covering all fuels for which CO_2 default values are provided. EPA has specified in the final rule that only CH_4 and N_2O emissions from combustion of those fuels listed in Table C-2 of Subpart C are required to be reported.

EPA has revised §98.33 to deal with certain unconventional combustion processes and types of fuel. In the Preamble, EPA has explained that "devices such as thermal oxidizers and pollution control devices . . . would report only the GHG emissions from the firing of supplemental fossil fuels." EPA believes that these provisions satisfy the intent of Part 98, to collect accurate and consistent GHG emissions data that can be used to inform future decisions.

The commenter should note that Tables C-1 and C-2 of the proposed rule have been consolidated into Table C-1 of the final rule, and the "solvent" fuel has been deleted. Furthermore, EPA has added default values for rendered animal fat and other biogenic fuels to Table C-1.

EPA has substantially revised the Tier 2 and Tier 3 sampling requirements. In many cases, sampling frequency has been reduced to ease the burden on reporters.

Commenter Name: Jeffrey A. Sitler
Commenter Affiliation: University of Virginia (UVA)
Document Control Number: EPA-HQ-OAR-2008-0508-0675.1
Comment Excerpt Number: 9

Comment: UVA has stationary combustion units that operate on natural gas, distillate oil, and coal. Based on our current fuel analysis frequencies, these units fall somewhere between Tier 1 and Tier 2 calculations. §98.34(c)(1) and (2) state that monthly sampling and analysis of natural gas and distillate oil is required and weekly sampling of coal is required. Our natural gas supplier provides the heat content on a monthly basis. Natural gas is very stable in quality. As part of our Title V, we obtain fuel certifications for coal and oil delivered to our permitted units. Distillate oil heating values have changed recently with the removal of sulfur, however, it very constant for the heat and sulfur content of the fuel. To provide an improvement over Tier 1 calculations, we request that we be allowed to use fuel supplier data for fuel oil and natural gas quality in the Tier 2 calculations. Monthly sampling by UVA of these fuels would be overkill given the low variability in these fuel supplies and our other permit requirements. Our coal supplier is required to sample each and every rail car of coal and provide us with the analysis before delivery. Once the coal is delivered, it is stored in silos until it is burned. In addition, we are not a large coal consumer, usually less than 20,000 tons/year. The quality of the coal we burn does not vary significantly and storing the coal in a silo maintains its delivered quality. We request that we be allowed to use fuel supplier data for coal quality in the Tier 2 calculations. Resampling this coal is unnecessary.

Response: The mandatory fuel sampling and analysis requirements for Tiers 2 and 3 have been considerably revised. The final rule requires that natural gas be sampled semiannually. For fuel oil and coal, a representative sampling is required for each fuel lot, i.e., for each shipment or delivery. The final rule also clarifies that fuel sampling and analysis data provided by the supplier may be used in the emission calculations.

Commenter Name: Rhea Hale
Commenter Affiliation: American Forest & Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2008-0508-0909.1
Comment Excerpt Number: 4

Comment: If the use of default emission factors as described in Tier 1 requirements, applied at the facility level, are not the primary source of data for stationary source combustion, EPA should provide specific changes as outlined below:
1. EPA should allow use of vendor fuel purchase records in conjunction with vendor provided fuel specific heating values and carbon content. Using vendor supplied data will result in calculated emissions that are just as accurate as those based on fuel analysis performed by the final consumer. This would lessen the burden on facilities and make the standard more cost effective, while likely providing more accurate data. In this scenario, one vendor could perform the required test and make it available to all customers. Costs would be decreased and one value would be used for the same fuel as opposed to slightly different values that each facility is likely to generate by using different labs. There is no technical basis that would suggest that a facility level fuel test is more accurate than one done by the fuel vendor. While we are working together with the Western Climate Initiative (WCI) to continue to improve its GHG Reporting Requirements, in its recent release of the final draft of the GHG Reporting Requirements, vendor supplied heating and carbon values are accepted.
2. Direct measurement of fuel properties, as required by Tier 2 and 3 in the proposal, should be optional. Most regulated facilities have internal control procedures to determine which method is the most consistent and accurate for their operations given their fuels and fuel systems and multiple data collection and reporting requirements. In addition, AF&PA recommends that the 250 MMBtu threshold for the Tiering system be based on fossil fuel energy input and not the energy input from biogenic sources. The extra cost of the higher measurement standard is not warranted generally, but particularly for biogenic fuels.
3. AF&PA recommends that the Tier 1 methodology be allowed for gaseous and liquid fossil fuels in units of all sizes and not limited to those less than 250 MMBTU/hr. The impacts associated with GHGs from these types of fuels are well understood and accepted and there is no additional benefit to requiring Tier 3 methodology for larger units that combust these fuels. In addition, the allowance for biomass combustion in 98(b)2 should be expanded to allow for liquid and gaseous biomass fuels, as biomass fuels are currently available in all three forms and are likely to become more widely available in the future. There should not be a measurement cost penalty for using biomass fuels in any of their available forms.
4. Similarly, EPA proposes to require monthly heating value determinations and monthly carbon content determinations for spent pulping liquors. Instead, AF&PA recommends that EPA allow the use of the IPCC (2006) default heating value of 11.8 TJ LHV/Gg (equivalent to 10.7 MMBtu HHV short ton BLS).

Response: See the Preamble, Section II. L., on General Monitoring Requirements for the overall rationale for methodologies required under this rule.

EPA chose not to adopt simplified calculation methods as a general monitoring approach (e.g., using default emission factors) for all units because the data would be less accurate than under the selected option and would not make use of site-specific data that many facilities already have available and refined calculation approaches that many facilities are already using. EPA is not allowing reporters full flexibility to use any method because the accuracy and reliability of the data would be unknown. Because consistent methods would not be used under such an approach, the reported data would not be comparable across similar facilities.

The final rule clarifies that fuel sampling and analysis data provided by the supplier may be used in the emission calculations, and that fuel billing meters may be used to quantify fuel consumption. To simplify the emission calculations in Tiers 2 and 3, arithmetic averaging of HHV and carbon content data is permitted if these data are obtained at least at the minimum frequency specified in §98.34, but less frequently than monthly (see §98.33(a)(2)(ii)). If sampling is more frequent, the reporter must calculate a weighted average according to Equation C-2b. However, regardless of the sampling frequency, the owner or operator must use the results of all available valid fuel analyses in the emissions calculations.

EPA has expanded the use of the Tier 2 Calculation Methodology for CO_2 emissions to include units with a maximum rated heat input capacity greater than 250 mmBtu/hr in which the only fossil fuels combusted are pipeline natural gas and/or distillate oil. The mandatory fuel sampling and analysis requirements for Tiers 2 and 3 have also been considerably revised. The final rule requires that natural gas be sampled semiannually. For fuel oil and coal, a representative sampling is required for each fuel lot, i.e., for each shipment or delivery. For other liquid fuels and biogas, quarterly sampling is required. For other solid fuels, excluding municipal solid waste, weekly composite sampling with monthly analysis is required. For other gaseous fuels, the daily sampling requirement has been retained, but only for facilities with existing equipment in place that is capable of providing the data. Otherwise, weekly sampling is required.

EPA has expanded the use of the Tier 1 Calculation Methodology for CO_2 emissions to include units greater than 250 mmBtu/hr that combust the biogenic fuels listed in Table C-1, unless the owner or operator already determines the HHV of the biogas or biodiesel at least quarterly. In this case Tier 2 shall be used. The commenter should note that EPA has added emission factors to Table C-1 for liquid and gaseous biomass-derived fuels including biogas, ethanol, biodiesel, rendered animal fat, and vegetable oil.

Regarding the use of the IPCC default high heat value for spent pulping liquors, EPA has not incorporated the commenter's suggestion. The final rule retains the requirement to periodically determine the HHV.

Commenter Name: Kimberly S. Lagomarsino
Commenter Affiliation: Mississippi Lime
Document Control Number: EPA-HQ-OAR-2008-0508-1568
Comment Excerpt Number: 4

Comment: Mississippi Lime Company agrees with EPA's proposal to allow HHV's (for Tier 2 calculations) to be obtained from fuel suppliers, as contained in Section V.C.3.a of the Preamble. Such a proposal greatly simplifies data collection endeavors for affected facilities.

Response: EPA appreciates the commenter's support. The final rule further clarifies that fuel sampling and analysis data provided by the supplier may be used in the emission calculations.

Commenter Name: Linda Farrington
Commenter Affiliation: Eli Lilly and Company (Lilly)
Document Control Number: EPA-HQ-OAR-2008-0508-0680.1
Comment Excerpt Number: 25

Comment: The requirement in §98.33(c)(4) to generate site specific CH_4 and N_2O emissions factors based on the results of source testing when default factors have not been provided in Table C-3 is very costly, and provides little to no environmental benefit. Since emission factors for hazardous waste and process vent streams are not provided in Table C-3, source testing will be the only option available for hazardous waste incinerators or thermal oxidizers. Comments submitted to this docket by the Coalition for Responsible Waste Incineration (CRWI) include further technical justification for not reporting CH_4 and N_2O based upon the likelihood of these compounds being emitted from high temperature incineration processes.

Response: EPA acknowledges the concerns of the commenter. EPA has decided to retain the requirement to report CH_4 and N_2O emissions both in metric tons of each gas and in metric tons of CO_2e. To this end, EPA has also decided to retain the separate emission factors and calculations for CH_4 and N_2O. EPA believes that using fuel-based default emission factors to report these gases separately provides an appropriate balance between easing the reporting burden on facilities and collecting useful data on GHG emissions.
The final rule excludes from calculations any CH_4 and N_2O emissions from fuels for which default emission factors have not been provided. Table C-2 has been revised to include CH_4 and N_2O emission factors for more fuels, including blast furnace gas and coke oven gas, as well as generic emission factors covering all fuel types listed in Table C-1. EPA has also deleted the provision in the proposed rule which allowed facilities burning other fuels to develop site-specific emission factors based on the results of source testing. Finally, hazardous waste incinerators that do not combust any supplemental fuels are excluded from the stationary combustion source category in §98.30. Only emissions from supplemental fuels combusted in these units must be reported.

Commenter Name: Jeffrey A. Sitler
Commenter Affiliation: University of Virginia (UVA)
Document Control Number: EPA-HQ-OAR-2008-0508-0675.1
Comment Excerpt Number: 3

Comment: UVA has twenty-nine small fuel oil burning units spread across campus, none of which have any metering. Currently, it appears that §98.34(c) requires monthly measuring of the fuel to meet these proposed regulations. We suggest that in lieu of metering or manual stick readings, we use fuel delivery metering to document fuel usage. Over a several year period of record, any discrepancies between delivered and burned fuel will disappear.

Response: EPA has revised the rule to allow the use of Tier 2 for units of any size combusting only pipeline quality natural gas and/or distillate oil. The Tier 2 methods do not require direct fuel flow measurement, but instead require fuel consumption to be quantified using company records, which could include fuel delivery metering. A definition of "company records," as it pertains to quantifying fuel consumption, has been added to §98.6. The commenter should note that the fuel sampling frequencies in §98.34 have been substantially revised: the final rule requires fuel oil to be sampled once per fuel lot, rather than monthly.

Commenter Name: See Table 6
Commenter Affiliation:
Document Control Number: EPA-HQ-OAR-2008-0508-0679.1
Comment Excerpt Number: 118

Comment: §98.38, Table C-3. The fuel type of "Totes" should be "Tires".

Response: EPA has corrected this error in the final rule.

Commenter Name: David R. Case
Commenter Affiliation: Environmental Technology Council (ETC)
Document Control Number: EPA-HQ-OAR-2008-0508-0664.1
Comment Excerpt Number: 2

Comment: The Proposed 4-Tier Emission Calculation Methods Cannot Be Practically Applied By Hazardous Waste Incinerators To Calculate CO_2e Emissions. The methods EPA has proposed for calculating CO_2e emissions do not practically and reasonably apply to such facilities. The Tier 4 methodology requires the use of a certified CEMS to quantify CO_2 mass emissions. This method requires the installation of a CO_2 monitor and a stack gas volumetric flow rate monitor, and is intended for facilities that already have existing CEMS equipment installed. In fact, EPA's rationale is that the incremental cost of adding a diluent gas monitor or flow monitor, or both, "would likely not be unduly burdensome" for a facility that is "already required to install, certify, maintain, and operate CEMS and to perform ongoing QA testing of the existing monitors." However, hazardous waste incinerators, although stringently regulated under MACT emission standards, are not required to have CEMS. Most hazardous waste incinerators do not have gas monitors or stack flow monitors, so this rule would require these facilities to install, certify, maintain, and operate expensive equipment solely for the purpose of calculating CO_2e emissions. A reasonable estimate of the cost to purchase and install such equipment at a hazardous waste incinerator is in excess of $100,000, exclusive of personnel training costs and ongoing certification and maintenance. We do not believe that EPA has or can justify the imposition of such high costs on a relatively small sector of facilities for the marginal benefit, if any, of including hazardous waste incinerators in the GHG emission reporting program. The Tier 3 methodology requires periodic determination of the carbon content of the fuel, using consensus standards (ASTM methods) and direct measurement of the amount of fuel combusted. However, the "fuel" for hazardous waste incinerators is a wide range of chemical wastes that have highly varying carbon content. As explained above, hazardous waste incinerators do not use a homogenous fossil fuel or process input that can be sampled weekly and composited for monthly analysis. To the contrary, incinerators process whatever chemical wastes are obtained from customers on a batch feed basis. The hazardous wastes range from contaminated water to chemical sludges, from aerosol cans to bulk liquids, from high BTU refinery slop oil to dilute solvent streams. The hazardous wastes vary enormously not only in composition and physical properties, but even more dramatically from day-to-day and month-to-month. To make matters even more complicated, the wastes are often mixed and agitated at the point of waste feed into the incinerator to achieve necessary BTU, constituent content, and physical properties for safe and effective operation of the hazardous waste incinerator. Determining the carbon content of hazardous waste feeds to an incinerator for purposes of the Tier 3 calculation would be almost a chimerical task. The weekly sampling and monthly composite analysis methodology in the proposed rule would be problematic. The cost and operational burden of sampling and analysis to obtain representative data on the carbon content of the wide and varying range of hazardous waste streams that are destroyed in an incinerator cannot, and has not, been justified by EPA. We do not believe that the Tier 3 methodology can be practically applied to hazardous waste incinerators. The Tier 2 and 1 methods do not appear to be available to hazardous waste incinerators. Tier 2 applies only to units with lower heat input capacity, and default emission factors for both Tier 2 and 1 do not appear to apply to hazardous wastes. We do not believe there is any practical method for calculating CO_2e emissions from the incineration of hazardous wastes. Before hazardous waste incinerators can be included in a GHG emission reporting program, EPA must adequately explain and justify how emission calculations would be conducted on a practical and reasonable basis.

Response: EPA, in response to these concerns, has revised the rule so that units that combust hazardous waste will only be required to report GHG emissions from any supplemental fuels (for which default values are provided) that are combusted in the unit.

Commenter Name: Paul J. Wolff
Commenter Affiliation: WolffWare
Document Control Number: EPA-HQ-OAR-2008-0508-0729.1
Comment Excerpt Number: 2

Comment: Two techniques that can be used to measure CO_2 emissions are CEMS and with a carbon mass balance. Both of these have accuracy limitations that will obscure the effect heat rate improvements have on reducing CO_2 emissions. A review of unit efficiencies computed from CEMS data can show step events and long term trends with changes that exceed 10%. A key challenge with CEMS is that it is very difficult to measure a gas flow rate with a high degree of accuracy. This problem is compounded when multiple units emit through a common stack. The most significant error for the carbon mass balance will be the sampling and weighing error of the fuel stream. The magnitude of this error is difficult to quantify, however, ASME PTC 4 [Footnote: American Society of Mechanical Engineers. "PTC 4 – 1998 Fired Steam Generators," 1999. 3 U.S. Geological Survey Coal Quality Database] provides some insight. A typical uncertainty for an input-output method, which also requires that the fuel stream be weighed and sampled, is stated to be in the range of 3 to 6%. The largest contributor to the error is created by sampling and weighing the fuel stream to determine the chemical energy entering the boiler. Similar errors can be expected to occur with a carbon mass balance approach, even under well controlled test conditions. The most effective means to report CO_2 emissions is to require that coal fired plants measure and report unit efficiency and then to quantify CO_2 emissions from efficiency with a fixed emission factor [see DCN: EPA-HQ-OAR-2008-0508-0729.1 for equation]. Basing the CO_2 emissions on unit efficiency is appropriate because it is what plant personnel will manage to control the CO_2 emissions. There are well defined methods published by the ASME (ASME performance test codes) for measuring the efficiency of the Rankine power cycle and of the individual components. The ASME heat loss method in conjunction with a measurement of turbine cycle efficiency is one of the most accurate ways to quantify the efficiency of a fossil unit. The heat loss method has improved accuracy over the input-output approach because it is not based on determining the total heat input by weighing and sampling the fuel stream. Basing the CO_2 emissions on a fixed emission factor is appropriate because once a plant chooses to burn a certain type of coal, any changes that occur will be due to random variations in the fuel and in the measurement of its carbon content. This approach is also consistent with EPA's current method for determining heat rate from CO_2 emissions. Furthermore coal data in a USGS database3 supports this idea. Figure 1 [See DCN: EPA-HQ-OAR-2008-0508-0729.1 for figures provided by commenter] presents the data, categorized by coal rank, of the CO_2 emission factor for the coal in the USGS database. To create these plots, the data were categorized by coal rank and averaged based on the BTU value (the bins were 500 BTU's). These data show that the emission factors computed from the USGS data agree well with the EPA emission factors. This is especially true for bituminous coal and for subbituminous coal when restricted to a range of 8,000 to 10,000 BTU. Figures 2 through 5 present the emission factors for given coal ranks categorized by selected geographic regions. Figure 2 presents the emission factors for bituminous coal for various geographic regions, while Figure 3 presents the variation relative to the EPA emission factor. The geographic regions selected were the ones containing the most coal samples. Figure 3 shows that in general there are small differences in the emission factors for bituminous coal among the different coal regions. For example bituminous emission factors deviate by no more than 2.7% from the EPA recommended value. This is within the measurement tolerance that would be achieved with sampling and measurement methods. Figures 4 and 5 show that the variation for subbituminous and lignite are larger, 3.6 and 4.8% respectively, however the size of the data sets are substantially smaller than the bituminous data set. Therefore, for a given coal rank, any differences between emission factors are within or very close to the measurement tolerances. The variation of the coal for a given coal rank and geographic region is shown in Figures 6 and 7. Figure 6 shows the variation among individual data points that occurs for bituminous coal in the Northern Applachian Region while Figure 7 quantifies the variation in the data by showing the minimum, maximum, and the percent difference between the minimum and maximum values. The maximum difference is 13.7% and generally exceeds 9% for most of the values. This range is consistent with variations I have observed in batches of coal received by a given power plant. If CO_2 emissions are based on the actual measurement of the carbon concentration in the fuel, similar variations would result in the CO_2 measurement. These random variations obscure the connection between unit efficiency and CO_2 emissions and will reduce the incentive for power companies to maintain and improve unit efficiency. There is a unique opportunity to create legislation that provides the necessary incentives for power companies to improve the efficiency of their coal fired units. There are several benefits to be gained by following this approach: 1. There would be a clear and measurable incentive for power companies to improve the efficiency of their coal fired units. The potential economic incentives include an industry wide reduction in CO_2 emissions that could range from 57 to 95 million metric tons. The financial incentives include a reduction in fuel costs for the power industry that range from 1.4 to 2.4 billion dollars. 2. There would be a clear incentive for power companies to create more energy from more efficient units. The benefits for this are comparable to the benefits that would be received by increasing the efficiency of a unit. 3. Fixed emission factors would eliminate the need for power companies to implement extensive programs to sample the fuel and measure carbon at the plant level. It would also eliminate a factor that could be gamed to artificially reduce a unit's CO_2 emissions.

Response: See the Preamble, Section II. L., for the response on the general monitoring approach.

EPA is not opposed to innovative, alternative approaches for estimating CO_2 mass emissions. The commenter suggests that basing CO_2 emissions on unit efficiency and a "fixed emission factor" will provide more accurate data than mass balance methods or CEMS. However, the commenter did not provide any supplementary information, proposed rule language, or cost analysis to demonstrate how the proposed method could be implemented. In view of this, EPA has not incorporated the commenter's suggested approach into the final rule, but is willing to consider it in a future rulemaking, if the necessary technical details of the method and cost estimates are provided for Agency review.

Commenter Name: Catherine H. Reheis-Boyd
Commenter Affiliation: Western States Petroleum Association (WSPA)
Document Control Number: EPA-HQ-OAR-2008-0508-0983.1
Comment Excerpt Number: 2

Comment: WSPA notes that there is a conflict between language in the Preamble and the text shown in the rule. The Preamble states that CEMS are only required for combustion devices fired by solid fuels, or otherwise required by existing rules or permits. However, the rule language regarding selection of the "Tier" level (Section 98.33 (b)(5)), as currently written, would require CEMS for any combustion unit that has a maximum rated heat input greater than 250,000 Btu/hr or that ran for more than 1,000 hours in any year since 2005. California refineries have already invested significant capital and hardware down a different path that yields equivalent, if not greater, accuracy using continuous High Heating Value (HHV) or carbon content analyzers. These installations are already in use in fulfilling the obligations under California's Mandatory Reporting Regulation. EPA's provision requiring CEMs would be duplicative, and result in no additional information nor serve any useful purpose in a GHG program. Recommendation: EPA should eliminate the conflict by modifying the language in the rule to match the Preamble. EPA should also expressly allow the use of HHV and/or carbon content analyzers in Tier 3.

Response: EPA acknowledges the commenter's concerns regarding Tier 4 applicability. EPA has revised §98.33(b)(4)(ii) of the final rule to clarify that all six criteria specified in subparagraphs (A) through (F) must be met before Tier 4 is required. The commenter should note that the Tier 2 methods use measured HHV, while the Tier 3 methods use measured carbon content. Please refer to §98.34 for more information on acceptable HHV and carbon content sampling and analysis methods.

Commenter Name: Matthew Frank
Commenter Affiliation: Wisconsin Department of Natural Resources
Document Control Number: EPA-HQ-OAR-2008-0508-1062.1
Comment Excerpt Number: 9

Comment: The framework outlined in the proposed rule for GHG reporting for ethanol production is straightforward, understandable and comprehensive. If EPA requires the calculation of these emissions, please identify the emission factors to be used.

Response: See the Preamble section on ethanol production.

At this time, EPA is not going final with the Ethanol Production Subpart. The sources of GHG emissions at ethanol production facilities that were to be reported under the proposed rule were stationary fuel combustion, onsite landfills, and onsite wastewater treatment. EPA has decided not to finalize the portion of 40 CFR Part 98, Subpart HH (Landfills) that addresses industrial landfills, nor 40 CFR Part 98, Subpart II (Wastewater Treatment). Stationary fuel combustion sources at ethanol production facilities are subject to the requirements of 40 CFR Part 98, Subpart C if general stationary fuel combustion emissions exceed the 25,000 metric tons CO_2e threshold. As EPA considers next steps, we will be reviewing the public comments and other relevant information.

Based on careful review of comments received on the proposal Preamble, rule and technical support documents under proposed 40 CFR Part 98, Subparts J, HH, and II, EPA will perform additional analysis and consider alternatives to data collection procedures and methodologies contained in those subparts.

EPA has revised the list of fuels in Table C-1, and has added emission factors for a number of biogenic fuels, including ethanol.

Commenter Name: See Table 8
Commenter Affiliation:
Document Control Number: EPA-HQ-OAR-2008-0508-0709.1
Comment Excerpt Number: 9

Comment: Proposed section 98.33(b)(5) on 74 Fed. Reg. 16,634 would require the use of Tier 4 calculation methodology – i.e. continuous emissions monitoring (CEMS) – for a unit that falls in four listed categories: There are no "ands" or "ors" between the four listed categories, so we do not know whether a unit would be subject to CEMS if it fell into just one category, or if it would only trigger CEMS if it fell into all four categories. We request that EPA clarify this provision. We assume you meant to insert the word "or" in the list, so that a unit would trigger CEMS if it fell into any one category. Further, we oppose the imposition of CEMS on any unit that "has operated for more than 1,000 hours in any calendar year since 2005." See section 98.33(b)(5)(C). A unit might operate more than 1,000 hours and yet still be a minor source that has not had to previously install CEMS to comply with some other regulatory requirement. [This would be burdensome and would impose an unnecessary economic hardship on smaller sources. For natural gas-fired sources, there is no need to impose CEMS. An accurate measure of CO_2e

from combustion of natural gas can be calculated based on the natural gas used by the unit, as measured by the gas billing meter. As we discuss with respect to Subpart NN below, these gas billing meters are the "cash registers" that determine how much natural gas a customer has used and must pay for. There are strong economic interests on both sides of the transaction to ensure that this data is accurate. No purpose would be served by requiring expensive and duplicative CEMs for such gas billing metered units.

Response: EPA acknowledges the commenter's concerns regarding Tier 4 applicability. EPA has revised §98.33(b)(4)(ii) of the final rule to clarify that all six criteria specified in subparagraphs (A) through (F) must be met before Tier 4 is required. The final rule also clarifies that fuel sampling and analysis data provided by the supplier may be used in the Tier 2 and 3 emission calculations, and that fuel billing meters may be used to quantify fuel consumption.

Commenter Name: Sean M, O'Keefe
Commenter Affiliation: Hawaiian Commercial and Sugar Company (HC&S)
Document Control Number: EPA-HQ-OAR-2008-0508-1138.1
Comment Excerpt Number: 9

Comment: EPA has proposed a four-tiered approach to monitoring and calculating CO_2 emissions from stationary combustion sources, and proposes requiring stationary combustion sources with heat inputs greater than 250 million BTU per hour (250 MMBTU/hr) to utilize the most stringent emissions calculation methods (i.e., Tiers 3 and 4) while sources smaller than 250 MMBTU/hr in size would be allowed to use more simplified methods (Tiers 1 and 2) with the option to use the more stringent methods if desired. The use of Tier 3 emissions calculation methods will impose significantly greater burdens and costs on regulated facilities than would the use of Tier 2 or Tier 1 emissions calculation methods. The Tier 2 calculation methodology would require the use of the monthly measured higher heating value (HHV) of each fuel combusted (if available) in conjunction with default fuel-specific CO_2 emission factors and would allow fuel consumption to be based on company records; if monthly measured HHV is not available, then the Tier 1 methodology (employing both a fuel-specific default CO_2 emission factor and higher heating value) could be used. The Tier 3 methodology would require periodic determination of the carbon content of the fuel (and molecular weight for gaseous fuels), along with direct measurement of the amount of fuel combusted. In addition to incurring ongoing analytical costs, facilities utilizing the Tier 3 methodology may need to install specialized fuel sampling equipment in order that representative samples of fuels can be obtained for analysis in compliance with referenced methods. In some cases, means for direct measurement of the amount of fuel combusted may also need to be installed. A&B believes that requiring units larger than 250 MMBTU/hr in size to use Tier 3 methods will unfairly and arbitrarily impose higher costs and regulatory burdens on some facilities and will not significantly improve the accuracy of overall estimates of GHG emissions, since facilities with multiple small emission units may have the same or higher overall emissions than facilities with a single larger unit. The rule should allow facility operators to select from any of these three emissions calculation methodologies rather than imposing a stricter standard based on an arbitrary emission unit size threshold.

Response: See the Preamble, Section II. L., on General Monitoring Requirements for the overall rationale for methodologies required under this rule, and the response to comment EPA-HQ-OAR-2008-0508-0909.1 excerpt 4 and EPA-HQ-OAR-2008-0508-0580 excerpt 10 for the rationale for methodologies required under Subpart C.

EPA has revised the rule to significantly expand the use of Tier 1 and Tier 2 Calculation Methodologies. In general, units of any size combusting the biogenic fuels listed in Table C-1 may use Tier 1. The 250 mmBtu/hr restriction on the use of Tier 2 has been lifted for units in which the only fossil fuels combusted are pipeline quality natural gas and/or distillate oil, in view of the homogeneous nature of these fuels. For a homogeneous fuel such as pipeline natural gas, monthly sampling is not necessary. For other fuels such as oil and coal, which are delivered in shipments or lots, requiring monthly sampling may be impractical; new fuel lots or deliveries may not be received on a monthly basis. Therefore, §98.34 has been revised to require that natural gas be sampled semiannually. For fuel oil and coal, a representative sampling sample is required for each fuel lot, i.e., for each shipment or delivery. For other liquid fuels and biogas, quarterly sampling is required. For other solid fuels, excluding municipal solid waste, weekly composite sampling with monthly analysis is required. For other gaseous fuels, the daily sampling requirement has been retained, but only for facilities with existing equipment in place that is capable of providing the data. Otherwise, weekly sampling is required.
The final rule clarifies that fuel sampling and analysis data provided by the supplier may be used in the emission calculations, and that fuel billing meters may be used to quantify fuel consumption. To simplify the emission calculations in Tiers 2 and 3, averaging of HHV and carbon content data is permitted if these data are obtained at least at the minimum frequency specified in §98.34, but less frequently than monthly (see §98.33(a)(2)(ii)). If sampling is more frequent, the reporter must calculate a weighted average according to Equation C-2b. However, regardless of the sampling frequency, the owner or operator must use the results of all available valid fuel analyses in the emissions calculations.

Commenter Name: Rhea Hale
Commenter Affiliation: American Forest & Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2008-0508-0909.1
Comment Excerpt Number: 9

Comment: AF&PA believes that the proposed rule requires Tier 4 methodology for determining CO_2 from boilers with fuel input capacity greater than 250 MMBtu/hr, and where a required CEMs has been already installed and the CEMs has a gas monitor of any kind, or a volumetric flow rate monitor, or both and the unit burns solid fossil fuels or MSW as a primary or secondary fuel. AF&PA seeks clarification that all of these conditions must be true to require Tier 4 methodology and not just certain elements.

Response: EPA acknowledges the commenter's concerns regarding Tier 4 applicability. EPA has revised §98.33(b)(4)(ii) of the final rule to clarify that all six criteria specified in subparagraphs (A) through (F) must be met before Tier 4 is required.

Commenter Name: Lawrence W. Kavanagh
Commenter Affiliation: American Iron and Steel Institute (AISI)
Document Control Number: EPA-HQ-OAR-2008-0508-0695.1
Comment Excerpt Number: 9

Comment: Subpart C requires reporting of combustion unit CH_4 and N_2O emissions using default values for various fuels shown in Table C-3. No values are presented for coke oven gas. We are not aware of any reliable emission factors for these gases for coke oven gas combustion but believe concentrations of these gases to be insignificant, if present at all, in the combustion products of coke oven gas and suggest deleting this requirement for coke oven gas combustion sources.

Response: EPA acknowledges the concerns of the commenter. Table C-2 has been revised to include CH_4 and N_2O emission factors for more fuels, including blast furnace gas and coke oven gas, as well as generic emission factors covering all fuel types listed in Table C-1. Section 98.33(c) of the final rule excludes from calculations any CH_4 and N_2O emissions from fuels that are not listed in Table C-2. EPA has also deleted the provision in the proposed rule which allowed facilities burning other fuels to develop site-specific emission factors based on the results of source testing.

Commenter Name: Jennifer Reed-Harry
Commenter Affiliation: PennAg Industries Association
Document Control Number: EPA-HQ-OAR-2008-0508-0948.1
Comment Excerpt Number: 9

Comment: We recommend that food processing operations which utilize alternative energy products, such as animal by-products, be required to conduct annual sampling vs. monthly sampling. When using a known, consistent energy source, the sampling documents consistent results. Requiring monthly sampling is an unnecessary expense which will not yield different results than annual sampling.

Response: EPA has revised the tier requirements. The use of Tier 1 calculation methods for CO_2 emissions has been expanded to include units greater than 250 mmBtu/hr that combust the biogenic fuels listed in Table C-1, provided that the owner or operator does not analyze or receive the results of an analysis for HHV of the biogas or biodiesel combusted at least quarterly. In that case, Tier 2 shall be used. Table C-1 has been revised to include default values for a number of biogenic fuels, including rendered animal fat.

Commenter Name: Lawrence W. Kavanagh
Commenter Affiliation: American Iron and Steel Institute (AISI)
Document Control Number: EPA-HQ-OAR-2008-0508-0695.1
Comment Excerpt Number: 8

Comment: Boilers located at independent coke plants would also be obligated to report CO_2 emissions from combustion of fuels in these units. Typically they are fired with excess coke oven gas but may be supplemented with natural gas. (As is the case for emissions associated with coal combustion under Subpart KK, CO_2 emissions attributed to natural gas consumption are accounted for under obligations for natural gas suppliers in Subpart NN.) Although some coke plants have boilers with rated capacities below 250 MMBTUH and would qualify for Tier 1 methodology, other plants have boilers with capacities exceeding 250 MMBTUH and would be required to apply Tier 2 or Tier 3 methodology. For all of the reasons noted above, we respectfully request that Tier 1 methodology apply to coke oven gas-fired boilers regardless of size. Reporting of emissions associated with coke oven combustion stacks and coke oven gas-fired boilers or other combustion sources, whether under Tier 1 or Tier 2, necessitates the addition of a coke oven gas and blast furnace gas default values in Table C-1 or C-2.
Response: The commenter should note that EPA has added emission factors to Table C-1 for both blast furnace gas and coke oven gas. This will reduce the burden on sources by allowing units smaller than 250 mmBtu/hr combusting these fuels to use Tier 1 or Tier 2. However, units larger than 250 mmBtu/hr combusting these fuels will be required to report using Tier 3, due to the fuels' potential variability. The commenter should note that the fuel sampling requirements have been reduced to weekly for units combusting alternative gaseous fuels which do not have the equipment in place for daily sampling. EPA has also removed the cumulative 250 mmBtu/hr restriction on unit aggregation, and has clarified the common pipe reporting option.

Commenter Name: Rhea Hale
Commenter Affiliation: American Forest & Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2008-0508-0909.1
Comment Excerpt Number: 7

Comment: AF&PA believes the methodologies for calculating emissions from biomass combustion should be as simple as possible. It is encouraged by the inclusion of Tier 1 methodology for biomass combustion for units of all sizes. In the pulp and paper industry, most boilers which burn biomass also burn one or more fossil fuels. Where a facility is co-firing biomass, it should be allowed to estimate the fossil fuel-related emissions using a mass balance approach (emission factors and activity data) as in other fuel combustion calculations. Facilities with regulated Continuous Emissions Monitoring systems (CEMs) can use them as an alternative method if a reasonable means exists to translate CEMs data into GHG estimates. In such instances, however, back-calculating of biogenic carbon dioxide from biomass (versus fossil fuels) using operating and emissions factors remains a necessary calculation making the added value of the monitoring to be little or none. Whether or not a CO_2 monitor is in place, emissions from biomass need to be calculated (or back-calculated from steaming rate and fossil fuel use data) in order to be backed out of the GHG emissions estimates. EPA does not address boilers that burn a combination of fossil and biomass fuels where CEMs are not used. From existing guidance one may assume that the Tier 1 methods can be used for estimating the biomass-related emissions from combination fuel fired boilers not equipped with CEMs, but this is not clear from the guidance. AF&PA interprets the proposed rule to allow Tier 1 methods for estimating biomass-related emissions as appropriate for boilers burning biomass in addition to fossil fuels, and requests clarification from EPA on this topic.

Response: EPA has considerably revised the methods provided to calculate CO_2 emissions from biogenic fuels. Emissions from biogenic fuels combusted in a unit of any size can be calculated using Tier 1, provided that the fuels combusted are listed in Table C-1 and the mass of the biogenic fuel combusted can be accurately quantified using available information. However, if the fuels combusted consist of biogas or biodiesel, and the HHV of the fuel is sampled at least at the minimum required frequency, Tier 2 shall be used. EPA believes that the methods provided in §98.33(e) are sufficient for calculating biogenic emissions from combination boilers, and that it is not necessary to include the Tier 5 methods from the Pulp and Paper TSD.

Commenter Name: Rhea Hale
Commenter Affiliation: American Forest & Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2008-0508-0909.1
Comment Excerpt Number: 3

Comment: The approach which would best satisfy EPA's stated intent (and is AF&PA's preferred approach) would be to follow the conventions established by the Canadian and European Union's programs and allow the use of national average fuel-specific emission factors, those factors published by the IPCC, or site specific factors determined (through experience) to be even more appropriate for the specific example under evaluation. Direct measurement of carbon content and heat content of fuels is an additional burden that is not justified by relative improved accuracy. Instead we propose that activity data and default emissions factors as described in Tier 1 requirements, applied at the facility level, be the primary source of data for stationary source combustion - as is allowed under most, if not all, GHG reporting systems. This approach will allow for quality and consistent data with respect to reported emissions. EPA could continue to allow the more advanced Tiers as options facilities might use as deemed appropriate to the circumstances.

Response: See the Preamble, Section II. L., for the response on the general monitoring approach.

See the response to comment EPA-HQ-OAR-2008-0508-0464.1 excerpt 4 for a description of EPA's approach to tiers.

EPA disagrees with the commenter's suggestion of allowing Tier 1 reporting for all units and facilities. EPA did not choose to adopt a simplified calculation method approach (e.g., using default emission factors) for all units because the data would be less accurate than under the selected option and would not make use of site-specific data that many facilities already have available and refined calculation approaches that many facilities are already using.

However, EPA has significantly expanded the use of Tier 1 and Tier 2 Calculation Methodologies. Most units of any size combusting the biogenic fuels listed in Table C-1 may use Tier 1. The 250 mmBtu/hr restriction on the use of Tier 2 has been lifted for units in which the only fossil fuels combusted are natural gas and/or distillate oil, in view of the homogeneous nature of these fuels. However, the 250 mmBtu/hr unit size cutoff remains for units that combust other fossil fuels, and higher tiers are required for those units.

Commenter Name: Robert D. Bessette
Commenter Affiliation: The Council of Industrial Boiler Owners (CIBO).
Document Control Number: EPA-HQ-OAR-2008-0508-0513.1
Comment Excerpt Number: 4

Comment: EPA is proposing use of default emission factors for those emissions from fuel combustion, but requests comment on more specific factors that could be applied. By EPA's own admission, the total quantity of potential CH_4 and N_2O emissions from fuel combustion is insignificant compared to CO_2 emissions. Since reductions in CO_2 emissions associated with reduced fuel use will automatically reduce CH_4 and N_2O emissions, there is simply no justification to impose additional costs for any more detailed approach to those emissions. In fact, they could be considered de minimis and ignored with no major impact on overall results. CIBO recommends that both CH_4 and N_2O emissions be excluded from stationary fuel combustion source reporting. The overall levels of emissions from these two gases are disproportionately low as compared to CO_2 (e.g., total CO_2e emissions of CH_4 and N_2O from natural gas combustion is less than 0.1% of the CO_2 emissions for natural gas combustion per Tables C-1 and C-3 of the proposed rule), and therefore estimating and reporting their emissions creates a disproportionately high burden on sources.

Response: See the Preamble, Section II. C., and the response to comment EPA-HQ-OAR-2008-0508-0561.1 excerpt 2 for information on the rationale for reporting for CH_4 and N_2O.

EPA has decided to retain in the final rule the requirement to report CH_4 and N_2O from stationary combustion sources. EPA believes that the use of fuel-specific emission factors for these pollutants strikes an appropriate balance between minimizing the burden on reporters and obtaining valuable GHG emission data. EPA has, however, revised the final rule to exclude CH_4 and N_2O emissions from fuels for which the rule does not provide emission factors, and has deleted the provision allowing the owner or operator of a facility to develop site-specific emission factors for such fuels. EPA believes that this change will reduce the reporting burden on facilities.

Commenter Name: Robert D. Bessette
Commenter Affiliation: The Council of Industrial Boiler Owners (CIBO).
Document Control Number: EPA-HQ-OAR-2008-0508-0513.1
Comment Excerpt Number: 25

Comment: §98.33 - Stationary fuel combustion source emissions calculation methods. The proposed methods require use of annual fuel consumption from company records. Specific alternative methods of determining fuel consumption are not spelled out, but it is assumed that the covered entities would have considerable flexibility in determining the annual fuel consumption. The following is but one example of the complications of determining fuel use.

For many solid fuel fired units such as stoker coal fired boilers and pulverized coal fired boilers utilizing volumetric coal feeders, there is no way to measure weight rate of coal feed to the boilers. In those cases, alternative methods of determining heat input and annual fuel consumption need to be used. For example, the Tier 2 methodology for Medical Solid Waste (MSW) fired units allows for use of boiler steam output and the maximum rated heat input to design steam output ratio to determine heat input.

A similar approach could also be used for other solid fuel fired units. Similarly, in cases where byproduct fuels are fired or co-fired, the covered entity should have latitude to utilize any methods appropriate for the unit that provide representative determination of CO_2 emissions. Providing flexibility in fuel consumption determination methodology will decrease the cost of the reporting program with an insignificant impact on overall emissions accounting accuracy. It is assumed that this is EPA's intention based on the reference to relying on company records.

Response: The use in Tier 2 of steam production and combustion unit efficiency to calculate CO_2 emissions is extended to other solid fuels in addition to municipal solid waste (MSW). These parameters may also be used to quantify the amount of biomass combusted in a unit.

In Tiers 1, 2, and 3, solid fuel consumption is determined by company records. EPA has defined the term "company records" in §98.6 of the final rule. EPA believes that the revised definition provides appropriate guidance as to what records a facility may use to determine fuel consumption.

Commenter Name: Robert D. Bessette
Commenter Affiliation: The Council of Industrial Boiler Owners (CIBO).
Document Control Number: EPA-HQ-OAR-2008-0508-0513.1
Comment Excerpt Number: 26

Comment: §98.33 and Table C-1 - GHG emission calculations and Table C-1. These correctly reference use of higher heating values. However, there is no stipulation that the HHV for solid fuels must be based on the As-Received analysis, which includes moisture content and represents the quality of the fuel as it is combusted. The alternative approach is to use the dry analysis, which excludes moisture and corrects all other components for zero moisture. The correct approach is to use the As-Received analysis per ASTM test methods. The HHV values given in table C-1 are representative of typical As-Received heating values. This needs to be clearly stated in the rule to avoid confusion and to ensure accurate results.

Response: EPA does not agree with the commenter. For consistency in implementing the mandatory reporting rule, the high heat values must be on a dry basis. The moisture content of coal "as-received" can vary considerably from site to site.

Commenter Name: Robert D. Bessette
Commenter Affiliation: The Council of Industrial Boiler Owners (CIBO).
Document Control Number: EPA-HQ-OAR-2008-0508-0513.1
Comment Excerpt Number: 27

Comment: §98.33(a) - Requirement to determine CO_2 emissions from fuel combustion for each stationary unit. EPA should provide more flexibility in the calculation and reporting requirements in order to allow use of available data that is representative of the combustion units. For example, if total fuel use is metered for a facility or combination of combustion sources, the use of the combined data should be allowed for determining total emissions for those sources on a monthly or annual basis. The Tier 3 methodology at 74 FR 16632 mentions that tank drop measurements may be used; the drop in tank level is only representative of fuel combusted for the combination of combustion units supplied from that common storage tank. Section 98.36(c)(3) of the proposed rule allows use of common pipe configurations. 74 FR 16638. Since EPA allows use of those methods, a similar approach should be allowed for any combustion unit types for any Tier and included in paragraph §98.33(a) for clarity.

Response: Combining units that have a common fuel source or exit through a common stack is allowed in the proposed and revised rule. In addition, the cumulative 250 mmBtu/hr heat input capacity limit on the aggregation of units into a group has been dropped. Rather, the 250 mmBtu/hr restriction applies only to the individual units in the group. Therefore, for reporting purposes, individual units with maximum rated heat input capacities of 250 mmBtu/hr or less may be aggregated without limit into a single group, provided that the Tier 4 methodology is not required for any of the units, and all units in the group use the same tier for any common fuel(s) that they combust. Units with maximum rated heat inputs greater than 250 mmBtu/hr must report as individual units, unless they burn the same type of fuel (oil or gas) provided by a common pipe or supply line; in that case, the owner or operator may opt to use the common pipe reporting provisions in §98.36(c)(3). Units using Tier 4 must report as individual units unless they share a monitored common stack; in that case, the common stack reporting provisions of §98.36(c)(2) may be used.

Commenter Name: Robert D. Bessette
Commenter Affiliation: The Council of Industrial Boiler Owners (CIBO).
Document Control Number: EPA-HQ-OAR-2008-0508-0513.1
Comment Excerpt Number: 28

Comment: For liquid fuels, fuel delivery documentation or invoices should be allowed as being indicative of fuel combusted in units combusting that fuel, with proper year-end inventory correction. Similarly, natural gas volume identified by the gas supplier for a facility by billing or invoice data should be allowable for use in determining total annual volume combusted in applicable combustion units.

Response: EPA has revised the rule to allow the use of Tier 2 for units of any size combusting only distillate oil and/or pipeline quality natural gas. Tier 2 allows the use of company records to determine fuel use. The final rule also clarifies that fuel billing meters may be used to quantify fuel consumption in Tiers 1 – 3. To simplify the emission calculations in Tiers 2 and 3, averaging of HHV and carbon content data is permitted if these data are obtained at least at the minimum frequency specified in §98.34, but less frequently than monthly (see §98.33(a)(2)(ii)). If sampling is more frequent, the reporter must calculate a weighted average according to Equation C-2b. However, regardless of the sampling frequency, the owner or operator must use the results of all available valid fuel analyses in the emissions calculations.

Commenter Name: Robert D. Bessette
Commenter Affiliation: The Council of Industrial Boiler Owners (CIBO).
Document Control Number: EPA-HQ-OAR-2008-0508-0513.1
Comment Excerpt Number: 29

Comment: EPA should precisely state how the Tier system affects reporting requirements. For example, EPA should provide answers to questions such as the following: If a facility reports in a certain Tier for one unit, must it report using that Tier for all units at the facility? If a facility reports using a certain Tier for one unit, can it go back to using a lower Tier in the future for that unit if circumstances change (i.e., a modification to the unit that deems old data unusable for estimating emissions after the modification)? If a facility volunteers to report at a certain Tier for one year, must it continue to use that Tier for reporting in every year after?

Response: In response to comments, EPA has added §98.33(b)(6) of the final rule to explain that different tiers may be used for different fuels in the same unit, unless the use of Tier 4 is required or elected, in which case the "total reported CO_2 emissions from the combustion of all fuels shall be based solely on CEMS measurements." It is EPA's intent that different tiers may be used for different units at a facility. However, it is not EPA's intent that facilities modify units to qualify for a lower reporting tier, such as through the removal of existing CEMS. EPA selected the tier approach to reporting in an effort to appropriately balance the burden on reporters with the need to collect accurate data on greenhouse gas emissions.

Commenter Name: Robert D. Bessette
Commenter Affiliation: The Council of Industrial Boiler Owners (CIBO).
Document Control Number: EPA-HQ-OAR-2008-0508-0513.1
Comment Excerpt Number: 30

Comment: §98.33(a)(1) - Fuel analysis. Tier 1 methodology only allows use of the Table C-1 default values. Tier 2 requires use of monthly analyses. EPA should provide more flexibility by allowing use of site specific fuel analysis values that would be more representative of fuels combusted than the default values. Those site specific values could be available from site samples and analyses or from supplier provided analyses on some frequency that is less frequent than monthly.

Response: The rule allows facilities to use a higher tier than the minimum required. EPA has also revised the sampling requirements for Tiers 2 and 3. For a homogeneous fuel such as pipeline natural gas, monthly sampling is not necessary. For other fuels such as oil and coal, which are delivered in shipments or lots, requiring monthly sampling may be impractical; new fuel lots or deliveries may not be received on a monthly basis. Therefore, §98.34 has been revised to require that natural gas be sampled semiannually. For fuel oil and coal, a representative sampling sample is required for each fuel lot, i.e., for each shipment or delivery. For other liquid fuels and biogas, quarterly sampling is required. For other solid fuels, excluding municipal solid waste, weekly composite sampling with monthly analysis is required. The final rule also clarifies that fuel sampling and analysis data provided by the supplier may be used in the emission calculations.

Commenter Name: Robert D. Bessette
Commenter Affiliation: The Council of Industrial Boiler Owners (CIBO).
Document Control Number: EPA-HQ-OAR-2008-0508-0513.1
Comment Excerpt Number: 31

Comment: §98.33(a)(2) and (3) - Monthly fuel analysis. Tier 2 and 3 methodology requires monthly analyses of fuels. Gaseous fuels (especially pipeline quality natural gas) and liquid fuels meeting a purchase specification typically do not vary significantly over time, so that a single analysis or supplier analysis would be adequate to provide site specific CO_2 emissions quantification. The analysis could be verified on an annual basis either by onsite sampling and analysis or by supplier analysis if required. On-site gas sampling is not an easy task, and reliance on fuel supplier analyses should be encouraged. In addition, a common sample and analysis is applicable to all combustion units on the site that combust the particular fuel; use of common analyses should be specifically provided in the rule. EPA should provide these flexibility measures as a means to lower compliance and reporting costs.

Response: EPA has revised the Tier 2 and 3 sampling requirements. The use of Tier 2 calculation methods for CO_2 emissions has been expanded to include units greater than 250 mmBtu/hr that combust only pipeline natural gas and/or distillate oil. For a homogeneous fuel such as pipeline natural gas, monthly sampling is not necessary. For other fuels such as oil and coal, which are delivered in shipments or lots, requiring monthly sampling may be impractical; new fuel lots or deliveries may not be received on a monthly basis. Therefore, §98.34 has been revised to require that natural gas be sampled semiannually. For fuel oil and coal, a representative sampling sample is required for each fuel lot, i.e., for each shipment or delivery. For other liquid fuels and biogas, quarterly sampling is required. For other solid fuels, excluding municipal solid waste, weekly composite sampling with monthly analysis is required.

The final rule also clarifies that fuel sampling and analysis data provided by the supplier may be used in the emission calculations, and that a single analysis of a fuel is applicable to all units at that facility combusting the fuel.

Commenter Name: Robert D. Bessette
Commenter Affiliation: The Council of Industrial Boiler Owners (CIBO).
Document Control Number: EPA-HQ-OAR-2008-0508-0513.1
Comment Excerpt Number: 32

Comment: §98.33(a)(2) and (3) - Tier 2 and 3 require monthly analyses of fuels. Solid fuels in many cases are obtained from multiple sources, so that determining monthly analyses would entail considerable cost. EPA should allow for use of representative samples and analyses on a less frequent basis. A provision should also be included to allow use of common solid fuel analyses for all units combusting a particular fuel and for supplier-provided analysis.

Response: EPA has revised the Tier 2 and 3 sampling requirements. For fuel oil and coal, a representative sampling sample is required for each fuel lot, i.e., for each shipment or delivery. The data from the analysis of this sample may then be used for any units combusting the fuel. The final rule also clarifies that fuel sampling and analysis data provided by the supplier may be used in the emission calculations.

Commenter Name: Robert D. Bessette
Commenter Affiliation: The Council of Industrial Boiler Owners (CIBO).
Document Control Number: EPA-HQ-OAR-2008-0508-0513.1
Comment Excerpt Number: 33

Comment: §98.33(b)(5) and §98.36(c)(2). Tier 4 (CEMS) methodology should specifically address and allow for CEMS installation and monitoring at various potential locations, e.g., in a common stack for multiple units, in a stack or duct upstream of a stack serving a single unit, in a common duct serving multiple units. Flexibility in application can reduce the cost of compliance. §98.36(c)(2) does mention common stacks, but not common duct arrangements. EPA should clarify in the final rule that other potential arrangements might be used. In addition, Tier 4 should permit flexibility for sources where CEMS are already located on site. There is no provision for alternatives or allowing a different Tier for reporting if there is a case where it is not feasible to upgrade the CEMS, but where the source could use another Tier to ensure reporting compliance.

Response: EPA acknowledges the commenter's concerns. In the final rule, EPA has added provisions for the use of CEMS in common stack or duct arrangements to §98.36(c)(2). The commenter has not provided an explanation of how it might not be feasible to upgrade to CEMS, making it impossible for EPA to determine whether or not additional flexibility is warranted.

Commenter Name: Robert D. Bessette
Commenter Affiliation: The Council of Industrial Boiler Owners (CIBO).
Document Control Number: EPA-HQ-OAR-2008-0508-0513.1
Comment Excerpt Number: 35

Comment: §98.33(c)(4) references Table C-4, but there is no Table C-4 in the rule.

Response: The provisions in §98.33(c)(4) of the proposed rule have been deleted.

Commenter Name: Steven J. Rowlan
Commenter Affiliation: Nucor Corporation (Nucor)
Document Control Number: EPA-HQ-OAR-2008-0508-0605.1
Comment Excerpt Number: 6

Comment: There are substantial differences between GHG and acid rain reduction through control of SO_2 and NO_x emissions, the focus of the ARP. These differences suggest that there should be a different focus between the two programs. One of the most fundamental differences is that CEMS are not a useful answer to the problem of variability. EPA has suggested that CEMS are a useful answer to the variability inherent in the steel process. This is less true than EPA may think. CEMS in the ARP are successful because the basic configuration of the electric power industry and its units lends itself to CEMS installation and accurate measurement. The same is much less true of the iron and steel industry. ARP facilities are typically using highly engineered, fully enclosed, controlled combustion sources designed to evacuate through a stack with minimal emissions. Iron and steel facilities are working with less-controlled, open process sources that generally cannot be fully enclosed, that suffer from significant process fugitive emissions requiring secondary capture, and which are typically semi-controlled for a variety of other minor sources. Thus, in a typical EAF melt shop, the canopy is controlling not only EAF emissions, but also partial contributions from preheaters and other apparatus (the rest of these emissions are typically lost fugitively through roof monitors, doors and similar openings). Thus, a CEMS is not measuring only EAF operations, but also a number of other sources, plus a large quantity of ambient influent air through the upper canopy.

Response: See the response to comment EPA-HQ-OAR-2008-0508-0455.1 excerpt 7 and the response to comment EPA-HQ-OAR-2008-0508-0580 excerpt 10 for EPA's rationale and approach to the use of CEMS.

This comment pertains to Electric Arc Furnace monitoring under the Iron and Steel subpart. See the individual source category section of the Preamble and separate comment response document for Iron and Steel.

Commenter Name: Burl Ackerman
Commenter Affiliation: J. R. Simplot Company
Document Control Number: EPA-HQ-OAR-2008-0508-1641
Comment Excerpt Number: 13

Comment: The rule allows for aggregation of units that have a combined maximum rated heat input capacity of 250 mmBtu/hr or less. We recommend allowing all units at a facility to be aggregated together. This will allow the facility to maintain a single fuel meter for each fuel type, which, in turn, will reduce the regulatory burden and expense and still provide facility level information as required by the rule.

Response: EPA has dropped the cumulative 250 mmBtu/hr heat input capacity limit on the aggregation of units. Rather, the 250 mmBtu/hr restriction applies only to the individual units in the group. Therefore, for reporting purposes, individual units with maximum rated heat input capacities of 250 mmBtu/hr or less may be aggregated without limit into a single group, provided that the Tier 4 methodology is not required for any of the units, and all units in the group use the same Tier for any common fuel(s) that they combust. Units with maximum rated heat inputs greater than 250 mmBtu/hr using Tiers 1, 2, and 3 must report as individual units, unless they burn the same type of fuel (gas or oil), and the fuel is provided by a common pipe or supply line; in that case, the owner or operator may opt to use the common pipe reporting provisions in §98.36(c)(3).

Commenter Name: Steven J. Rowlan
Commenter Affiliation: Nucor Corporation (Nucor)
Document Control Number: EPA-HQ-OAR-2008-0508-0605.1
Comment Excerpt Number: 19

Comment: Nucor supports the recommendation of SMA/SSINA that carbon content testing of pipeline quality natural gas be eliminated or the burden of providing that information shifted to the supplier, where one test would cover multiple facilities and eliminates the possibility of inconsistent carbon content reporting from facilities sharing a common pipeline. See SMA/SSINA comments, II.A.

Response: EPA has expanded the use of the Tier 2 calculation methodology based on fuel heating value to units of any size in which the only fossil fuels combusted are pipeline quality natural gas and distillate oil, in view of the homogeneous nature of these fuels. The final rule also revises the fuel sampling and analysis requirements for pipeline natural gas such that sampling and analysis is required only semiannually, and that data provided by the supplier may be used in the emission calculations.

Commenter Name: Pamela F. Faggert
Commenter Affiliation: Dominion
Document Control Number: EPA-HQ-OAR-2008-0508-1741
Comment Excerpt Number: 8

Comment: For combustion sources affected by Subpart C, we assume the provisions proposed in 98.33(b)(6), which allows the use of Tier 3 methods if the Tier 4 specified monitoring systems are not installed by January 1, 2010, would prevent a unit from being required to install Tier 4 monitoring equipment simply to determine applicability. We believe this is appropriate and request that EPA clarify that the use of Tier 3 methods is allowed to determine initial applicability if Tier 4 monitoring is not in place. In general, for Subpart C, EPA needs to explicitly state that if required equipment is not already being collected, analyzed or installed, the unit or facility may use the next lower Tier to estimate emissions for applicability purposes.

Response: EPA respects the effort that may be required to determine applicability and has modified the final rule in order to provide clarity. As stated in Subpart A of the final rule, any method in §98.33(a) may be used to calculate CO_2 emissions from general stationary combustion units for the purposes of applicability determination. EPA expects that a source should be able to determine applicability without installing new equipment.

Commenter Name: Rich Raiders
Commenter Affiliation: Arkema Inc.
Document Control Number: EPA-HQ-OAR-2008-0508-0511.1
Comment Excerpt Number: 36

Comment: EPA should clarify the §98.6 "fuel" definition to indicate that fuel "means solid, liquid or gaseous combustible materials that is intended to provide substantial heat input, as measured by HHV value, into a combustion device." EPA has previously recognized that materials below 5,000 British Thermal Units ("BTU") per pound ("lb") of material, as-fired, do not contribute significant heat of combustion in a combustion device. (74 Fed. Reg. 54, January 2, 2009, citing 63 Fed. Reg. 33781 and 64 Fed. Reg. 24251, the RCRA Comparable Fuels rule). In the existing comparable fuels regulations, EPA has addressed how much heating value is required before a material being combusted beneficially contributes heat generation. EPA's current scientific review indicates that heating values of materials being combusted below between 2,600 and 5,000 BTU/lb do not significantly contribute to the heat of combustion. As heat generation directly relates to combustion GHG emissions, which is EPA's interest in this proposal, EPA should limit the definition of "fuel" for Part 98 purposes to the RCRA comparable fuels definition. Below we clarify why the fuel definition should be restricted to materials intended to be combusted and providing significant heat value to a combustion device. Many materials described below may be combusted that do not significantly contribute to heating value, and should not be included as fuels subject to Part 98 monitoring, recordkeeping, and reporting. The EPA proposed definition of "fuel" includes all materials combusted at a reporting facility. This definition seems to inadvertently capture the thousands of air pollution control devices ("APCD") placed into service over the last half century to control volatile organic compound ("VOC") and other air emissions. Thousands of facilities have installed APCDs to comply with various EPA requirements, including the following: 1. Prevention of Significant Deterioration ("P SD") program at 40 CFR 51 and 52, specifically Best Available Control Technology ("BACT") and Lowest Achievable Emission Rate ("LAER") obligations; 2. NSPS at 40 CFR 60; 3. National Emissions Standards for Hazardous Air Pollutants ("NESHAP") at 40 CFR 61; 4. MACT at 40 CFR 63 and 65; 5. Reasonably Achievable Control Technology ("RACT") under the National Ambient Air Quality Standards ("NAAQS") programs implemented by the permitting authorities around the country; and 6. Various state and local air pollution control requirements. Facilities have installed these devices to bring many airsheds into NAAQS compliance as the several NAAQS standards have evolved, avoid potential public health and nuisance issues, and balance the needs of the manufacturing facilities and their surrounding communities. As these emission control technologies have evolved over the decades, EPA and the permitting authorities have developed a wide ranging collection of applicable requirements governing the design and operations of these devices, including regulating the required emissions loading to the device, the destruction and removal efficiency ("DRE"), and/or outlet emission rates of various materials. These emission control devices combust the "supplemental" fuel, typically natural gas, and the "vent gas" fuel, the materials being subjected to emission control. Most emission control devices manage vent gases containing carbon-bearing materials.

Response: EPA has expanded the list of exempted source categories to include portable equipment, emergency generators, flares, and units that combust hazardous waste. EPA believes that the content of the final rule addresses this comment through the revision of §98.33(b)(4) of the final rule, which provides a detailed discussion of the use of the Tier 1 and Tier 2 Calculation Methodologies. This section clarifies the criteria for applicability of these methodologies. In response to the comment, the Tier 1 and Tier 2 methodologies shall be used if a unit has a maximum heat capacity rating of 250 mmBtu/hr or below, or any size if it combusts natural gas or distallate fuel oil. Therefore, the use of Tier 1 and 2 is linked to the fuels listed in Table C-1 of the rule. It is EPA's intent that reporters, for combustion equipment such as APCDs that would be subject to Tier 1 or Tier 2 methods, are only expected to report emissions from the combustion of fuels that are specifically listed in Table C-1. If the fuel is not included in Table C-1, than an emission calculation is not expected for that fuel type.

Commenter Name: Gary Moore
Commenter Affiliation: Pensacola Plant of Ascend Performance Materials LLC
Document Control Number: EPA-HQ-OAR-2008-0508-0366.1
Comment Excerpt Number: 2

Comment: Offgas streams from various chemical processes are required to be controlled in flares, thermal oxidizers, boilers or other thermal control devices by various Federal Rules such as the HON, MON or PSD regulations. These off gas streams typically have low BTU values and do not independently support combustion. It is unclear from the definitions in§98.6 whether these off gas streams would be classified as fuels as they are not combustible in the traditional use of the term. A clarification of the definition of fuel is required. We propose that these off gas streams which are controlled for regulatory purposes be excluded from the definition of fuel or that a minimum heat input of 300 BTU/scf be added to the definition of fuel. (This value comes from EPA's minimum heat input allowed for assisted flares in 40 CFR 60.18(c)(3)(ii).)

Response: EPA has expanded the list of exempted source categories to include portable equipment, emergency generators, flares, and units that combust hazardous waste. EPA believes that the content of the final rule addresses this comment through the revision of §98.33(b)(4) of the final rule, which provides a detailed discussion of the use of the Tier 1 and Tier 2 Calculation Methodologies. This section clarifies the criteria for applicability of these methodologies. In response to the comment, the Tier 1 and Tier 2 methodologies shall be used if a unit has a maximum heat capacity rating of 250 mmBtu/hr or below, or any size if it combusts natural gas or distallate fuel oil. Therefore, the use of Tier 1 and 2 is linked to the fuels listed in Table C-1 of the rule. It is EPA's intent that reporters, for combustion equipment such as APCDs that would be subject to Tier 1 or Tier 2 methods, are only expected to report emissions from the combustion of fuels that are specifically listed in Table C-1. If the fuel is not included in Table C-1, than an emission calculation is not expected for that fuel type.

5. DETAILED GHG EMISSION CALCULATION PROCEDURES/EQUATIONS IN THE RULE

Commenter Name: Randy Armstrong
Commenter Affiliation: Shell Oil Company
Document Control Number: EPA-HQ-OAR-2008-0508-0651.1
Comment Excerpt Number: 8

Comment: Table C-3 (74 FR 16640-1664 1) Table C-3 in subpart C should include default methane (CH_4) and nitrous oxide (N_2O) emission factors for flexigas, consistent with the emissions factors adopted in California. Flexigas is a low Btu gas produced during flexicoking, where thermal cracking converts heavy hydrocarbons into light hydrocarbons. The applicable California emission factors for flexigas (referred to a derived gas, low BTU gases) are 0.3 g CH_4 per mmBtu and 0.1 g N_2O per mmBtu.

Response: EPA has clarified the methodology for calculating CH_4 and N_2O emissions in the final rule. Reporting of these emissions is required only for the fuels listed in the CH_4 and N_2O emission factor table (now Table C-2). Flexigas has not been added to Table C-2, therefore CH_4 and N_2O emission calculations are not required.

Commenter Name: Leslie Bellas
Commenter Affiliation: National Lime Association (NLA)
Document Control Number: EPA-HQ-OAR-2008-0508-0520.1
Comment Excerpt Number: 51

Comment: In Equation C-6 (40 C.F.R. 98.33), CO_2 = 5.18 x 10(-7) * C_{CO2} * Q needs to be clarified. This formula is similar to the formula listed in Appendix F of Part 75, except that the conversion factor in Part 75 is 5.7 x 10(-7). NLA requests clarification on why a different conversion factor was used in the Proposed Rule. Similarly, the unit label for C_{CO2} is not correct. It is shown as tons/scf - % CO_2, which is not mathematically correct. It should be corrected to show (tons/scf)/% CO_2 as shown in Appendix F of Part 75. Finally, this Equation should be clarified so that the % CO_2 concentration (term C_{CO2}) is not entered into the formula as a decimal fraction. For example, if the % CO_2 is 25%, then 25 should be used in the formula, not 0.25. This is because the conversion factor is in units of (tons/scf)/% CO. This is misleading as most calculations using a percent call for the decimal fraction representation.

Response: EPA has corrected the unit label for the conversion factor. It now reads (metric tons/scf/% CO_2). EPA believes that the value of the conversion factor provided in Equation C-6 is accurate, given these revised units.

Commenter Name: Dan F. Hunter
Commenter Affiliation: ConocoPhillips Company
Document Control Number: EPA-HQ-OAR-2008-0508-0515.1
Comment Excerpt Number: 21

Comment: Industrial and municipal solid waste incinerators appear to be subject to Tier 2 reporting in Subpart C. A HHV value is required in the equation contained in the subpart but no default value is provided. A default value would be helpful and reduce the risk and burden of complying with the weekly sampling/monthly composite analyses requirements of §98.34(c). The risk associated with sampling and analytical errors is large and the liability EPA references for missed data at 74 FR 16474 make this onerous. We do not believe this is warranted for such small emission sources as field industrial waste incinerators.

Response: EPA has added default HHV values for tires and municipal solid waste. Also, the final rule allows Tier 1 for a unit that combusts municipal solid waste but does not produce steam, if the use of Tier 4 is not required. However, EPA will require Tier 3, for the combustion of other fuels not listed in Table C-1 provided that Tier 4 is not required, fuels are not exempted from reporting, and the fuels provide at least ten percent of the annual heat input to the unit.

Commenter Name: Keith Adams
Commenter Affiliation: Air Products and Chemicals, Inc.
Document Control Number: EPA-HQ-OAR-2008-0508-1142.1
Comment Excerpt Number: 20

Comment: The proposed rule refers to a section §98.33(a)(1)(iv)(D) while describing the data needs for employing CO_2 CEMS. There is no such §98.33(a)(1)(iv)(D). Perhaps the agency meant to reference §98.33(e)(3)(ii)(D)?

Response: EPA has corrected this error. The paragraph referenced in the comment (§98.33(a)(4)(i) in the final rule) now refers to §98.33(a)(4)(iv).

Commenter Name: Dan F. Hunter
Commenter Affiliation: ConocoPhillips Company
Document Control Number: EPA-HQ-OAR-2008-0508-0515.1
Comment Excerpt Number: 20

Comment: For Tier 1 calculations, the Preamble (page 16473) says, "small stationary combustion units could use a default emission factor and heat rate to estimate emissions, and no fuel measurements would be required." A similar clarifying statement should added to the regulatory language in 98.33(a)(1).

Response: EPA believes that the language in §98.33(a)(1) clearly states that units using Tier 1 may use a fuel-specific default CO_2 emission factor and fuel consumption from company records. Fuel flow meters are not required for Tier 1 calculations. EPA has revised the definition of "company records" to provide further clarification as to what types of records are acceptable for the purposes of determining fuel consumption.

Commenter Name: Michael DiMauro
Commenter Affiliation: Massachusetts Municipal Wholesale Electric Company (MMWEC)
Document Control Number: EPA-HQ-OAR-2008-0508-0580
Comment Excerpt Number: 15

Comment: The formulas enumerated in 98.33 for the calculation of CO_2 emissions only allow for the measurement of oil consumption in volumetric units (i.e., gallons). However, certain types of oil meters measure oil directly as a mass flow (lb/hr) rather than a volume flow (gal/hour). i. Therefore, Formulas C-1, C-2a, and C-4 should be modified to account for situations in which oil usage is measured or documented in lbs rather than gallons. Note the formulas themselves should not require modification, only the Legend. ii. Table C-1 should provide default "high heat values" for oil in units of MMBtu/lb as well as units of MMBtu/gal.

Response: EPA appreciates your comment and has added language to the description of these equations in §98.33 clarifying that fuel can be expressed as volume or mass flow measurements for liquid fuels. Also, Table C-1 was expanded to include high heat values in units of mass and volume, depending on the fuel type.

Commenter Name: Michael DiMauro
Commenter Affiliation: Massachusetts Municipal Wholesale Electric Company (MMWEC)
Document Control Number: EPA-HQ-OAR-2008-0508-0580
Comment Excerpt Number: 13

Comment: It is suggested that the language in 98.33(a)(1) and 98.33(a)(2) describing the use of company records to document fuel usage be made consistent. For Tier I monitoring, the Proposed rule specifies that CO_2 emissions are calculated from "annual fuel consumption" determined from company records (98.33(a)(1)); while for Tier II monitoring, the Proposed rule specifies that CO_2 emissions are calculated from "the quantity of fuel combusted" as determined from company records (98.33(a)(2). Since the same type of company records would be used irrespective of whether the Tier I or Tier II monitoring scheme is applied, it would be preferable if both provisions employed the same term to describe fuel usage (i.e., either "consumption" or "combustion") in order to avoid confusion.

Response: The descriptions of the Tier 1 and Tier 2 methodologies in §98.33 were revised to address the noted inconsistency, and the description of the fuel variable under Equation C-1 and Equation C-2 are consistent. In addition, EPA refers the commenter to the definition of "company records" in §98.6 of the final rule for additional clarification regarding the use of the term.

Commenter Name: Mary J. Doyle
Commenter Affiliation: BG North America, LLC (BG)
Document Control Number: EPA-HQ-OAR-2008-0508-0714.1
Comment Excerpt Number: 11

Comment: BG supports the continued use of the current part 75 reporting requirements with this clarification. Proposed section 98.43 requires owners or operators of EGUs to "continue to monitor and report CO_2 mass emissions as required under §§75.13 and 75.64 of this chapter." Section 75.13 could be read to require all EGUs to have installed stack flow monitors or measure the carbon content of the fuel they burn. That is contrary to existing Part 75 reporting for gas and oil-fired EGUs. BG asks EPA to clarify that gas and oil-fired units be allowed to continue to use fuel flow monitors and Carbon based F-factors consistent with Appendix D and Appendix G of Part 75. Further, EPA should make clear that that gas and oil-fired EGUs will not be required to install stack flow monitors and conduct carbon sampling of the fuel they are combusting in connection with the proposed GHG reporting requirement.

Response: The final rule takes into account units that are not in the Acid Rain Program, but are required to monitor and report Part 75 heat input data under other regulatory programs such as the Clean Air Interstate Regulation (CAIR). New methods have been added to the four-tiered CO_2 emissions calculation methodologies in §98.33(a) for stationary combustion units.

One new method allows oil- and gas-fired units that report heat input data using Appendix D of Part 75 to use Equation G-4 in Appendix G of Part 75 to calculate hourly CO_2 mass emissions, which are summed over the reporting year. Another allows low mass emitting sources under §75.19 to calculate CO_2 mass emissions using their reported heat input data together with fuel-specific default CO_2 emission factors.

In addition, units that continuously monitor heat input using flow monitors and diluent gas (CO_2 or O_2) monitors may calculate CO_2 mass emissions using the CEMS data together with appropriate equations from Appendix F of Part 75.

Finally, Subpart D of the final rule provides a CO_2 calculation methodology for units that are not in the Acid Rain Program, but report CO_2 mass emissions year-round using Part 75 methodologies. At present, many units subject to the Regional Greenhouse Gas Initiative (RGGI) in the Eastern U.S. are in this category. For the purposes of Part 98, the CO_2 emissions from these units are calculated and reported the same way as the CO_2 emissions from Acid Rain Program units.

Commenter Name: Dan F. Hunter
Commenter Affiliation: ConocoPhillips Company
Document Control Number: EPA-HQ-OAR-2008-0508-0515.1
Comment Excerpt Number: 22

Comment: For Tier 3 methodology, the Preamble states this methodology is required for a unit with a maximum heat input capacity of greater than 250 mmBtu/hr. In 98.33(b)), "the Tier 3 Calculation Methodology may be used for a unit of any size, combusting any type of fuel, except when use of Tier 4 is required or elected." This section does not include language requiring the use of Tier 3 for units greater than 250 mmBtu/hr. ConocoPhillips requests EPA modify the language in this paragraph to "This methodology is required for liquid and gaseous fossil fuel-fired units with a maximum heat input capacity greater than 250 mmBtu/hr, and is required for solid fossil-fuel fired units that are not subject to Tier 4 provisions."

Response: In response to comments, EPA has substantially revised §98.33(b), describing which tier a reporter is to use. Provided that the use of Tier 4 is not required, EPA has decided to allow the use of Tier 1 methods for units of any size combusting distillate oil or natural gas, as long as the owner or operator does not routinely sample the fuel for HHV or receive the results of such a sampling at a frequency greater than or equal to the minimum frequency listed in §98.34, and Tier 2 methods for units of any size combusting only pipeline quality natural gas and/or distillate fuel oil.

Commenter Name: Keith A. Nagel
Commenter Affiliation: ArcelorMittal USA and Severstal North America
Document Control Number: EPA-HQ-OAR-2008-0508-0496.1
Comment Excerpt Number: 8

Comment: Section 98.33(a)(1) allows combustion sources to use less burdensome Tier 1 and Tier 2 methodologies where default emissions factors and heat input capacities are established for the type(s) of fuel burned. Those useful approaches can minimize the burden of reporting emissions from combustion sources while retaining high levels of accuracy. To make these methodologies available to the many steelmaking sources that combust blast furnace gas and/or coke oven gas, we request that EPA publish default CO_2 emission factors and high heat values for these process gases in Table C-1 as part of the final rule. EPA's Technical Support Document for the Iron and Steel Industry (the "Steel TSD") already contains information (including from well-respected international sources) regarding parameters that, while not perfect, are adequate for inclusion: 1. Page 5 of the Steel TSD indicates that blast furnace gas has a heating value of approximately 90 Btu/ft3; 2. Page 13 of the Steel TSD indicates that coke oven gas has a heating value of 500-600 Btu/ft3 (which can be averaged to 550 Btu/ft3); 3. Page 6 of the Steel TSD indicates that the CO_2 emission factor for blast furnace gas is 260 $MMTCO_2e$/TJ (from IPCC guidelines); and 4. Page 14 of the Steel TSD indicates that the CO_2 emission factor for coke oven gas is 0.35 $MMTCO_2e$/mt coke (from IPCC guidelines). The steel industry stands ready to work with EPA to take whatever steps are needed to finalize default and high heat values based on this information in time for promulgation in the final rule. Publication of these factors should be made with the mutual understanding that these values are not the "final word" on the heating value or emissions factors for these process gases and that future refinement based on additional study and testing is expected. To the extent individual facilities disagree with the initial numbers included in the final rule, they would retain the flexibility to voluntarily use Tier 3 or Tier 4 methodology as appropriate.

Response: EPA has included additional emission factors for Blast Furnace Gas and Coke Oven Gas in Table C-1 of the final rule.

Commenter Name: Leslie Bellas
Commenter Affiliation: National Lime Association (NLA)
Document Control Number: EPA-HQ-OAR-2008-0508-0520.1
Comment Excerpt Number: 22

Comment: 40 C.F.R. § 98.33(a)(4)(iv) permits the use of an O_2 monitor to meet the CEMS monitoring requirement for Tier 4. However, the Proposed Rule does not clearly indicate whether a facility with an O_2 monitor would be required to use a CEMS. An O_2 monitor can be used to indicate CO_2 emissions from combustion emissions because the concentration of both CO_2 and O_2 is dependent on the amount of air that is available for the combustion of fuels. O_2 cannot always, however, indicate the amount of CO_2 emissions from lime process emissions because process emissions are not dependent on how fuel is burned. 40 C.F.R. §98.33(a)(4)(iv) should be clarified to state that sources not allowed to use O_2 data as a surrogate for CO_2 would not be subject to Tier 4 solely on the basis of having an O_2 monitor. 40 C.F.R. §98.33(e)(2)(i), Equation C-12 refers to measuring the "hourly CO_2 concentration" and the "hourly stack gas volumetric flow rate." This Equation should be revised to replace "hourly CO_2 concentration" with "hourly average CO_2 concentration" and "hourly stack gas volumetric flow rate" with "hourly average stack gas volumetric flow rate" because the source will determine the hourly average CO_2 concentration and flow rate based on multiple samples that must be collected in accordance with Part 60 and 75 requirements.

Response: EPA has revised the final rule to provide clarity concerning gas monitors and Tier 4 requirements. Accordingly, Tier 4 shall be used if the unit meets six conditions, one of which is "The installed CEMS include a gas monitor of any kind or a stack gas volumetric flow rate monitor, or both . . ." Further, in §98.33(a)(5)(iv) EPA describes that "an oxygen (O_2) concentration monitor may be used in lieu of a CO_2 concentration monitor to determine the hourly CO_2 concentrations in accordance with Equation F-14a or F-14b (as applicable) in Appendix F to Part 75 . . . if the effluent gas stream monitored by the CEMS consists solely of combustion products (i.e., no process CO_2 emissions are mixed with the combustion products)."

Commenter Name: Ted Michaels
Commenter Affiliation: Energy Recovery Council (ERC)
Document Control Number: EPA-HQ-OAR-2008-0508-0544.1
Comment Excerpt Number: 6

Comment: 98.33 Calculation Methodologies In Tier 2 Equation C-2b. The "B" ratio is incorrect and should be revised consistent with the Western Climate Initiative calculation on which it was based. Revised ratio should be: Ratio of boilers maximum design rated heat input capacity to its design rated steam output capacity (mmBtu/lb steam). Same comment for equation C-10b for N_2O and CH_4 calculations.

Response: EPA appreciates the comment but believes that the ratio as described under Equation C-2c is satisfactory as written. The Agency directs the commenter to the definition of "maximum rated heat input capacity" in §98.6 for further clarification on this matter.

Commenter Name: Ted Michaels
Commenter Affiliation: Energy Recovery Council (ERC)
Document Control Number: EPA-HQ-OAR-2008-0508-0544.1
Comment Excerpt Number: 3

Comment: ERC Recommends Using the DOE 1605 (b) Methodology or a Modified Tier 2 Calculation Methodology Consistent with the WCI and DOE GHG reporting rules, EPA's final MRR should eliminate the requirement that large MWCs use the Tier 4 methodology. The DOE 1605 (b) approach is very similar to the calculation methodology used for reporting annual emissions of criteria pollutants and HAPs as required by Title V operating permits. Each year MWC facilities must conduct multiple stack or performance tests (under NSPS Subpart Eb/Cb) on all MWC units, over several days using EPA Methods 1 - 29. Some MWC facilities stack test twice per year, as some state requirements are more restrictive than the federal standards. The DOE approach would take advantage of these extensive testing requirements. The modified Tier 2 methodology would utilize multiple stack results over several days as follows: 1. Calculate facility average CO_2 concentration (%), stack gas flow rate (DSCF/Hour) and boiler load or steam production (Klbs/hour). 2. Calculate a Stack Flow to Load Ratio (SFLR) or DSCF/Hr per Klbs/hr steam production. The SFLR is analogous to the proposed Tier 2 "B" design heat input to steam ratio used in Equation C-2b, but could be considered more representative since it is based on actual test data. 3. Obtain biogenic/non-biogenic CO_2 fractions using ASTM Methods D 7459 and D 6866–06a from integrated gas samples collected during stack testing. 4. Use CO_2 concentration, total steam production and SFLR to calculate MWC unit and facility wide annual CO_2 emissions. The above approach modifies the Tier 2 methodology slightly since actual CO_2 concentrations are used (not a fixed emission factor), and mass CO_2 emissions are calculated from actual stack gas flow and actual steam production rather than using a fixed design heat input. Table 2 below summarizes 2008 non-biogenic CO_2 emissions from large (i.e., greater than 250 tpd) MWC facilities calculated in accordance with the proposed alternative methodology. [See submittal data table provided by the commenter.] Based on the above, a proposed third equation to Tier 2 Calculation Methodology would be: [See submittal data table provided by the commenter.] We recommend that the ASTM D6866-06a non-biogenic carbon fraction results be directly included in the calculation methodology for Municipal Solid Waste combustion. This will improve transparency in reporting GHG CO_2 emissions and eliminate potential for error in apportioning non-biogenic and biogenic CO_2 emission.

Response: See the Preamble, Section II. E., for an explanation of how this rule relates to State and regional programs, and Section II. D. for the response on how this rule relates to other U.S. government climate change efforts. EPA appreciates the commenter's suggested adjustment to the Tier Calculation Methodology, however EPA cannot accommodate each individual suggestion. Please note that the final rule significantly expands the use of Tier 1 and Tier 2 Calculation Methodologies.

Commenter Name: Edward N. Saccoccia
Commenter Affiliation: Praxair Inc.
Document Control Number: EPA-HQ-OAR-2008-0508-0977.1
Comment Excerpt Number: 3

Comment: The proposed rule imposes the Tier 4 calculation methodology on sources meeting the conditions specified under §98.33(b)(5)(ii). As worded, it appears any one of the (A), (B), (C), or (D) conditions would result in the Tier 4 method being required. This does not match the intent expressed in the Preamble to the proposed rule, and summarized in Preamble table C-1. In particular, Table C-1 appears to indicate that Tier 4 is required only for Solid Fossil Fuel fired units >250 mmBTU/hr (meeting other criteria, as well) and that Gaseous Fossil Fuel fired and Liquid Fossil Fuel fired combustion units are required to use no more rigorous than Tier 3 methods. The current language of §98.33(b)(5)(ii) would imply any of the conditions described in §98.33(b)(5)(ii)(A), (B), (C) or (D) trigger the Tier 4 method requirement. We believe the agency's intent is that all of the conditions described in §98.33(b)(5)(ii)(A), (B), (C) and (D) are necessary in order to trigger the Tier 4 method requirement. Clarify the requirement to employ the Tier 4 calculation method. Resolve the apparent discrepancy between the intent to limit Tier 4 to only Solid Fossil Fuel fired combustion units, per Table C-1 of the Preamble, with the actual imposition of Tier 4 described under §98.33(b) (5) (ii). Clarify that in order for Tier 4 to be required under §98.33(b)(5)(ii), all the conditions under §98.33(b)(5)(ii)(A), (B), (C), and (D) must be met. Specifically, conditions (A), (B), (C), and (D) should be separated by the word "and" – absent that, an implied "or" would force this calculation method on many other combustion units for which it was not intended.

Response: EPA acknowledges the commenter's concerns regarding Tier 4 applicability. EPA has revised the final rule to clarify that all six criteria must be met before Tier 4 is required. However, EPA disagrees with suggestions that Tier 4 should only be required if the installed CEMS include a CO_2 monitor. The Tier 4 CEMS requirement is limited to larger solid fossil fuel units with an existing pollutant CEMS and certified gas monitor or volumetric flow rate monitor. EPA is requiring the use of CEMS due to the complexity of monitoring solid fuel consumption and the heterogeneous nature of the solid fuels. Many of these fossil-fuel fired units with a pollutant CEMS have an existing diluent monitor (O_2 or CO_2) that can be used to determine CO_2 emissions. EPA's estimates of monitoring costs are averages for a representative facility and may not represent the actual cost in individual circumstances.

Commenter Name: William C. Herz
Commenter Affiliation: The Fertilizer Institute (TFI)
Document Control Number: EPA-HQ-OAR-2008-0508-0952.1
Comment Excerpt Number: 5

Comment: EPA should revise the NPRM to allow use of Tier 3 calculation methodology for those units required to use Tier 4 under 40 C.F.R. §98.33(b)(5)(ii) until the unit's first scheduled shutdown or other routine maintenance outage or turnaround based on regular industry practice. The NPRM's proposed 40 C.F.R. §98.33(b)(6)(ii) requires all sources to have stack flow volumetric analyzers and CO_2 concentration analyzers installed by Jan. 1, 2011. 74 Fed. Reg. at 16,634. For boiler American Society of Mechanical Engineers (ASME) Section 1 requirements, five-year inspections are required. Combustion sources would be forced to shut down to install stack flow volumetric analyzers and CO_2 concentration analyzers. Facilities should be able to use Tier 3 for no more than five years, until the facility's scheduled five-year ASME boiler inspection cycle. This approach would avoid the costs and environmental and safety implications of an additional shutdown by ensuring that the already-scheduled shutdown will coincide with the opportunity to install monitoring equipment necessary to comply with Tier 4 calculation methodology.

Response: EPA appreciates your comment and has adjusted the required Tier 4 start date for units that require CO_2 or O_2 monitor installations to January 1, 2011 if the monitor cannot be installed by January 1, 2010. Such units will report Tier 2 or Tier 3 to report for 2010. See §98.33(b). EPA considers this to be a reasonable amount of time to meet the Tier 4 requirements while also ensuring that Tier 4 facilities are employing consistent methodologies within a reasonable timeframe.

Commenter Name: John Piotrowski
Commenter Affiliation: Packaging Corporation of America (PCA)
Document Control Number: EPA-HQ-OAR-2008-0508-1029.1
Comment Excerpt Number: 4

Comment: PCA urges the Agency to limit emission calculations and recordkeeping requirements to fuel use tracking in combination with internationally accepted GHG calculation protocols such as the WRI/WBCSD Greenhouse Gas Protocol Calculation Tools and ICFPA/NCASI Spreadsheets for Calculating GHG Emissions from Pulp and Paper Manufacturing. The Agency's proposed emission calculation methodologies involving frequent fuel sampling and analysis, add-on CO_2 CEMs, daily process gas analysis, and detailed requirements for determining GHG releases from industrial wastewater treatment plants and landfills that are not only onerous, but they depart from existing, defensible and widely accepted procedures. In addition to being unnecessarily rigorous, the cost of complying with the Agency's requirements is high and comes at a time when our industry is already reeling from the impact of a severe and global economic decline. We believe that the Tier 1 requirements, when used in conjunction with an analytical tool like the ICFPA/NCASI Spreadsheets for Calculating GHG Emissions from Pulp and Paper Manufacturing will adequately and accurately represent carbon dioxide emissions from stationary combustion sources regardless of size or type of fuel fired. As our industry is a major energy consumer, it has been – and continues to be - in our best interest to carefully track fuel use and fuel cost. Therefore, we employ a number of mechanisms to account for fuel use as a matter of good business management. However, in the event that the tiered structure is retained in the rule, direct measurement of fuel higher heating value, carbon content, and molecular weight, as required by Tiers 2 and 3 should be optional but not required. Also, we recommend that the 250 MMBtu threshold be based solely on fossil fuel use and exclude biomass fuels. We object to the Rule's proposal to require the use of CO_2 CEMs on stationary sources with a rated capacity greater than 250 MMBtu/hr for several reasons: First, as cited above, there are effective alternative options to accurately quantify CO_2 emissions for stationary sources and those methods are workable for sources regardless of rated capacity. Second, we have power islands configured in a manner where effluent gases from multiple boilers co-mingle in a common exhaust stack. In this configuration, installing a dedicated CO_2 CEMs on one boiler but not another is problematic particularly if the CEMs sampling probe must be installed

prior to a control device. Attempting to analyze raw effluent gases in situ would likely result in chronic operating, maintenance and data reliability problems that would complicate, if not compromise, data quality. Third, a common stack configuration would appear to require dedicated fuel meters on each boiler – something that would require extensive downtime to install. This kind of project is typically reserved for planned maintenance outages that occur annually. As we are already past the annual outage period at all of our mills for 2009, the earliest this work would be done is in 2010 which means that 2011 would be the first year that a full complement of data would be available. Fourth, the pulp and paper industry is a heavy user of woody biomass fuel; this is particularly true at integrated facilities. Our company has a number of large (i.e., > 250 MMBtu/hr heat input) biomass-fired boilers that would be subject to the proposed CO_2 CEMs requirement. As the Rule's intent is to quantify and report fossil-fuel derived CO_2 emissions, we believe that requiring the installation of costly CEMs on biomass boilers for the purpose of quantifying non-reportable biogenic CO_2 emissions is an unnecessary expenditure of resources. At the very minimum, large biomass-fired boilers should be exempt from CO_2 CEMs monitoring requirements. However, we maintain that the proposed requirement to install CEMs on any boiler is unnecessary since there are simple, reasonable and defensible alternative methods available. Again, and we emphasize, CEMs systems (and ancillary support equipment) are very expensive to install, operate and maintain, particularly at a time when our industry is under extreme financial duress. These costs are compounded by the attendant requirements associated with missing data and data reporting requirements associated with CEMs operation at §98.35 and §98.36. Fifth, our industry frequently routes non-condensible gases (NCGs) to lime kilns and recovery furnaces for thermal destruction per sector-related MACT requirements. Proposed Tier 3 requirements impose daily gas analysis on days when NCGs are utilized. This presents a monumental logistical, analytical and cost burden on facilities handling NCGs in this fashion. In fact, we find that GHG emissions from the combustion of NCGs at our kraft mills accounts for less than 0.1% of total facility GHG releases. The effort associated with daily fuel analysis is grossly disproportional to any presumed data quality benefit assumed under the Rule. This requirement should be dropped in favor of a fuel throughput multiplied by a generally accepted emission factor calculation.
Response: See the Preamble, Section II. L., on General Monitoring Requirements for the overall rationale for methodologies required under this rule, and the response to comment EPA-HQ-OAR-2008-0508-0909.1 excerpt 4 and EPA-HQ-OAR-2008-0508-0580 excerpt 10 for the rationale for methodologies required under Subpart C.

EPA disagrees with the commenter's suggestion that Tier 1 should be permitted for all emissions monitoring. However, EPA has significantly relaxed the Tier requirements. The final rule significantly expands the use of Tier 1 and Tier 2 Calculation Methodologies. The 250 mmBtu/hr restriction on the use of Tier 2 has been lifted for units that combust natural gas and distillate oil, in view of the homogeneous nature and low variability in the characteristics of these fuels. However, the 250 mmBtu/hr unit size cutoff remains for units that combust residual oil and solid fossil fuel. EPA has also revised the criteria that trigger mandatory use of Tier 3. Tier 3 must be used for units larger than 250 mmBtu/hr, that combust fuels other than pipeline natural gas and/or distillate oil if Tier 4 is not required, the fuels are not exempted from reporting, and the fuels provide at least ten percent of the annual heat input to the unit. EPA believes that this provision will ease the monitoring burden on facilities which co-fire small quantities of waste liquids or gases along with fossil fuels such as coal.

The mandatory fuel sampling and analysis requirements for traditional fossil fuels have been relaxed for Tiers 2 and 3. EPA agrees with the commenters that for a homogeneous fuel such as pipeline natural gas, monthly sampling is not necessary. For other fuels such as oil and coal, which are delivered in shipments or lots, requiring monthly sampling may be impractical; new fuel lots or deliveries may not be received on a monthly basis. Therefore, §98.34 has been revised to require that natural gas be sampled semiannually. For fuel oil and coal, a representative sampling is required for each fuel lot, i.e., for each shipment or delivery. For other liquid fuels and biogas, quarterly sampling is required. For other solid fuels, excluding municipal solid waste, weekly composite sampling with monthly analysis is required. For other gaseous fuels, the daily sampling requirement has been retained, but only for facilities with existing equipment in place that is capable of providing the data. Otherwise, weekly sampling is required, which may be postponed in favor of monthly sampling until 2011 if new equipment must be purchased or if existing equipment must be upgraded to meet the weekly sampling and analysis requirements.

The final rule clarifies that fuel sampling and analysis data provided by the supplier may be used in the emission calculations, and that fuel billing meters may be used to quantify fuel consumption. To simplify the emission calculations in Tiers 2 and 3, averaging of HHV and carbon content data is permitted if these data are obtained at least at the minimum frequency specified in §98.34, but less frequently than monthly (see Equation C-2b). However, regardless of the sampling frequency, the owner or operator must use the results of all available valid fuel analyses in the emissions calculations.

Fuel flow meters are required for units combusting liquid or gaseous fuels and using Tier 3 reporting, though EPA has clarified that fuel billing meters and any fuel drop tank measurements based on consensus-based standards may be used. However, EPA has revised §98.34(d) to allow facilities until January 1, 2011 to calibrate these fuel flow meters. Facilities that operate continuously with infrequent outages may postpone the initial flow meter calibration until the next scheduled maintenance outage.
The final rule clarifies the applicability of the Tier 4 methodology. Many commenters were unsure whether only one or all six of the conditions listed in §98.33 must be met to trigger the requirement to use CEMS. EPA's intent has always been that a source must meet all six conditions to require the use of Tier 4. This has been made clear in the final rule text. One of these conditions is that "the unit combusts solid fossil fuel or municipal solid waste, either as a primary or secondary fuel." Therefore, units combusting only solid biomass (such as wood) would not be required to use Tier 4, and units of any size combusting wood, wood waste, or other solid biomass-derived fuels may use Tier 1 to report emissions.

EPA has clarified the use of common stack reporting for units using CEMS, and has added common duct provisions. See §98.36(c)(2), which allows the owner or operator to report the combined emissions from the units sharing the common stack or duct, in lieu of separately reporting the GHG emissions from the individual units, if the common stack is monitored per Tier 4. Also, fuel flow meters are not required for Tier 4, and the final rule has been revised to state that Tier 4 CO_2 emissions need not be reported by fuel type. Therefore the owner or operator would not need to install separate fuel flow meters. The owner or operator will need to report separately the common stack CO_2 emissions from fossil fuel and biomass fuel.

To calculate CH_4 and N_2O emissions by fuel type, when CEMS (which are not fuel-specific) are used, the total heat input measured by the CEMS must be apportioned to each fuel type. The owner or operator should use the best available information (e.g., fuel feed rates, GCV values, etc.) to do the necessary heat input apportionment.

Commenter Name: William C. Herz
Commenter Affiliation: The Fertilizer Institute (TFI)
Document Control Number: EPA-HQ-OAR-2008-0508-0952.1
Comment Excerpt Number: 4

Comment: EPA states in the NPRM Preamble that units will not be required to install monitoring systems to comply with the NPRM. 74 Fed. Reg. 16,493. However, the NPRM, as proposed in 40 C.F.R. §98.33(b)(5)(ii), appears to require all combustion sources with any type of analyzer to add stack gas volumetric flow rate monitors and CO_2 concentration analyzers and report under Tier 4. Several ammonia facilities have analyzers in place but do not have the stack gas volumetric flow rate monitors and CO_2 concentration analyzers required under Tier 4 methodology. Units cannot comply with Tier 4 requirements without installation of stack gas volumetric flow rate monitors and CO_2 concentration analyzers. Such installation would prove extremely costly (at least $275,000 per unit) and would be necessary at many facilities falling under this section's requirements. Such a requirement is contrary to EPA's express intent in the Preamble not to require installation of monitoring systems, but instead allow units to rely on Tier 3 rather than incur the installation expense of new equipment. EPA should clarify that a facility is not required to report using Tier 4 calculation methodology under the proposed 40 C.F.R. §98.33(b)(5)(ii) unless that unit meets all of the conditions specified in subparagraphs (A) through (F) of that section. In the alternative, EPA should include language in 40 C.F.R. §98.33(b)(5)(ii) clarifying that Tier 4 requirements will not apply to facilities that do not presently have stack gas volumetric flow rate monitors and CO_2 concentration analyzers. For example, under proposed 40 C.F.R. §98.33(b)(5)(iii)(A), units with a maximum rated heat input capacity of 250 mmBtu/hr or less that do not have stack gas volumetric flow rate monitors and CO_2 concentration analyzers are not required to report under Tier 4. 74 Fed. Reg. at 16,634. TFI would suggest a similar approach for facilities regulated under 40 C.F.R. §98.33(b)(5)(ii). As such, TFI recommends the following revision to proposed 40 C.F.R. §98.33(b)(5)(ii): 98.33(b) (5) The Tier 4 Calculation Methodology: (ii) Shall be used for a unit if the unit has both a stack gas volumetric flow rate monitor and a CO_2 concentration monitor. While TFI would prefer that EPA clarify that units that do not meet all of the conditions specified under 40 C.F.R. §98.33(b)(5)(ii)(A) through (F) may rely on Tier 3 calculation methodology, the above-recommended revisions to 40 C.F.R. §98.33(b)(5)(ii) would accomplish EPA's stated intent of not requiring installation of new monitoring equipment.

Response: EPA acknowledges the commenter's concerns regarding Tier 4 applicability. EPA has revised the rule to clarify that all six criteria specified in subparagraphs (A) through (F) must be met before Tier 4 is required. Among these criteria is that the unit has a maximum rated heat input capacity greater than 250 mmBtu/hr. However, EPA disagrees with suggestions that Tier 4 should only be required if the installed CEMS include a CO_2 monitor. The Tier 4 CEMS requirement is limited to larger solid fossil fuel units with an existing pollutant CEMS and certified volumetric flow rate monitor or gas monitor. EPA is requiring the use of CEMS due to the complexity of monitoring solid fuel consumption and the heterogeneous nature of the solid fuels. Many of these fossil-fuel fired units with a pollutant CEMS have an existing diluent monitor (O_2 or CO_2) that can be used to determine CO_2 emissions. EPA's estimates of monitoring costs are averages for a representative facility and may not represent the actual cost in individual circumstances.

Commenter Name: Michael S. Dae
Commenter Affiliation: Energy Developments, Inc. (EDI)
Document Control Number: EPA-HQ-OAR-2008-0508-0706.1
Comment Excerpt Number: 4

Comment: Table C-1 of Subpart C includes High Heat Values (HHV) for various fuel types. However, no specific HHV is listed for methane or LFG. The BTU value of methane is well established at 1,011 BTU/standard cubic foot (scf). Since LFG primarily consists of methane and carbon dioxide the HHV of LFG can be calculated based on its methane content, EDI requests that EPA consider adding a HHV for LFG to the Biogas fuel type in Table C-1. This value should be on the 1,011 BTU/scfm value for methane and the methane content of the LFG. HHV (mmBTU/scf) = [(1,011 BTU/scf) X (% Methane*/100)] / 1,000,000. Adding the above proposed calculation to Table C-1 could allow LFGTE facilities to calculate CO_2 emissions using the Tier 1 calculation, This would remove the requirement to sample the fuel gas on a monthly basis to determine HHV. Because the quality of LFG can vary daily based on operational and atmospheric factors, EDT believes that the proposed method for calculating the HHV from LFG would provide a more accurate value than that based on a single monthly gas sample. This method would actually be based on an increased data set and would provide better representation of the fuel combusted without the resultant sampling and analysis costs.

Response: EPA appreciates your comment and has included default HHV values in Table C-1 for captured methane.

Commenter Name: Vince Brisini
Commenter Affiliation: RRI Energy Inc. (RRI)
Document Control Number: EPA-HQ-OAR-2008-0508-0618.1
Comment Excerpt Number: 9

Comment: As liquid and gaseous fuel quantities are not only measured on a volume basis, US. EPA should expand its annual CO_2 mass emissions formulas for liquid and gaseous fuels to account for fuel quantities measured on either a volume or mass basis. The equations provided in Tier 3 for calculating annual CO_2 mass emissions for liquid and gas-fired combustion sources (i.e., Equations C-4 and C-5 of the proposed GHG reporting rule), would only allow for to be measured on a volume basis. However, companies use fuel flow meters that may directly measure the volume or mass of the fuel combusted.

Response: EPA appreciates your comment and has allowed mass flow measurements for liquid fuels by adding the following language to §98.33(b):

> "Fuel flow meters that measure mass flow rates may be used for liquid fuels, provided that the fuel density is used to convert the readings to volumetric flow rates. The density shall be measured at the same frequency as the carbon content, using ASTM D1298-99 (Reapproved 2005) Standard Test Method for Density, Relative Density (Specific

Gravity), or API Gravity of Crude Petroleum and Liquid Petroleum Products by Hydrometer Method (incorporated by reference, see §98.7)."

Commenter Name: Keith A. Nagel
Commenter Affiliation: ArcelorMittal USA and Severstal North America
Document Control Number: EPA-HQ-OAR-2008-0508-0496.1
Comment Excerpt Number: 29

Comment: Section 98.33(b)(6) allows sources working to install CO_2 CEMS to defer reporting until January 1, 2011 and provides that those sources "shall use the Tier 3 Calculation Methodology in 2010." One primary reason we are considering the potential use of CO_2 CEMS at certain sources is because Tier 3 reporting is either technically infeasible or unreasonably burdensome (absent the changes requested in these comments). Thus, it will not always be viable to use Tier 3 for the interim CO_2 CEMS installation period. Instead of specifying Tier 3 for this interim period, the Proposed Rule should allow sources to use the best available information.

Response: The final rule requires data collection for calendar year 2010, but has been changed since proposal to allow use of best available monitoring methods for the first part of 2010. EPA has clarified in §98.33(b) for those units installing and certifying CEMS to meet Tier 4 requirements, they may use either Tier 2 or 3 in 2010. It should also be noted that there were substantial revisions to Tiers 2 and 3, and the commenter should revisit these requirements.

Commenter Name: Jeffrey L. Clark
Commenter Affiliation: Environmental Coordinator, Teck Alaska Incorporated
Document Control Number: EPA-HQ-OAR-2008-0508-0142
Comment Excerpt Number: 6

Comment: Monthly analysis of carbon content of fuels seems excessive. Again is EPA being too precise without being accurate.

Response: The mandatory monthly fuel sampling and analysis requirements for traditional fossil fuels have been relaxed for Tiers 2 and 3. EPA agrees with the commenter that for a homogeneous fuel such as pipeline natural gas, monthly sampling is not necessary. For other fuels such as oil and coal, which are delivered in shipments or lots, requiring monthly sampling may be impractical; new fuel lots or deliveries may not be received on a monthly basis. Therefore, §98.34 has been revised to require that natural gas be sampled semiannually. For fuel oil and coal, a representative sampling is required for each fuel lot, i.e., for each shipment or delivery. For other liquid fuels and biogas, quarterly sampling is required. For other solid fuels, excluding municipal solid waste, weekly composite sampling with monthly analysis is required. For other gaseous fuels, the daily sampling requirement has been retained, but only for facilities with existing equipment in place that is capable of providing the data. Otherwise, weekly sampling is required, which may be postponed in favor of monthly sampling until 2011 if new equipment must be purchased or if existing equipment must be upgraded to meet the weekly sampling and analysis requirements.

The final rule clarifies that fuel sampling and analysis data provided by the supplier may be used in the emission calculations, and that fuel billing meters may be used to quantify fuel consumption. To simplify the emission calculations in Tiers 2 and 3, averaging of HHV and carbon content data is permitted if these data are obtained at least at the minimum frequency specified in §98.34, but less frequently than monthly (see Equation C-2b). However, regardless of the sampling frequency, the owner or operator must use the results of all available valid fuel analyses in the emissions calculations.

Commenter Name: Leslie Bellas
Commenter Affiliation: National Lime Association (NLA)
Document Control Number: EPA-HQ-OAR-2008-0508-0520.1
Comment Excerpt Number: 50

Comment: 40 C.F.R. 98.33(c)(4) refers to Table C-4, but no such table appears in the Proposed Rule.

Response: In the final rule, language in §98.33 that references Table C-4 has been deleted.

Commenter Name: Lorraine Krupa Gershman
Commenter Affiliation: American Chemistry Council (ACC)
Document Control Number: EPA-HQ-OAR-2008-0508-0423.2
Comment Excerpt Number: 50

Comment: In §98.33(a)(3)(iii), the proposed Tier 3 methodology for a gaseous fuel requires the use of Equation C-5, which contains the term MVC. MVC is defined as the molar volume conversion factor and is stated to be equal to 849.5 scf per kg-mole at standard conditions for this equation and also throughout the rule. However, in §98.6, Definitions, EPA defines the term "Standard Conditions or Standard Temperature and Pressure" as meaning 60 degrees F and 14.7 psia. Using a temperature of 60º F, molar volume is calculated to be (10.73)(520)/(14.7) = 379.6 scf/lb-mole x 2.2 = 835 scf/kg-mole. Thus, there appears to be a discrepancy between the standard conditions in the definitions and the standard conditions for the conversion factor in Equation C-5. It appears EPA may have used a temperature of 68 ºF to obtain a molar volume of 849.5 scf/kg-mole. Thus, the molar volume that is required to be used doesn't match with a standard temperature of 60 ºF. EPA could either revise the molar volume to closer to 835 or revise the definition of Standard Conditions to reflect a temperature of 68 ºF.

Response: EPA has revised the definition of "Standard conditions or standard temperature and pressure (STP)" in §98.6 to mean "68 degrees Fahrenheit and 14.7 pounds per square inch absolute." Given this revised definition, EPA believes that the value for MVC provided in Equation C-5 is correct.

Commenter Name: Lorraine Krupa Gershman
Commenter Affiliation: American Chemistry Council (ACC)
Document Control Number: EPA-HQ-OAR-2008-0508-0423.2
Comment Excerpt Number: 49

Comment: Calculation of Part 75 F factors should be allowed in Tier 3 as allowed in Tier 4.

Response: EPA has revised the rule to expand the use of Tier 2, which combines measured heat content with an emission factor similar to an F-factor, to large units greater than 250 mmBtu/hr that burn natural gas or distillate oil. EPA is providing additional alternative methods to reporters with units that report heat input data to EPA using Part 75, which allow the use of Appendix F and Appendix G methods in Part 75.

Commenter Name: Leslie Bellas
Commenter Affiliation: National Lime Association (NLA)
Document Control Number: EPA-HQ-OAR-2008-0508-0520.1
Comment Excerpt Number: 49

Comment: 40 C.F.R. 98.33(a)(1)(4)(i) refers to "(a)(1)(iv)(D) of this section," but NLA was unable to locate this provision. Did EPA intend to refer to 40 C.F.R. 98.33(a)(4)(i)?

Response: EPA has corrected this error. The paragraph (§98.33(a)(5)(i) in the final rule) now refers to §98.33(a)(5)(iv).

Commenter Name: Lorraine Krupa Gershman
Commenter Affiliation: American Chemistry Council (ACC)
Document Control Number: EPA-HQ-OAR-2008-0508-0423.2
Comment Excerpt Number: 46

Comment: Stationary fuel combustion source emissions calculation methods require use of annual fuel consumption from company records. Specific alternative methods of determining fuel consumption are not spelled out, but it is assumed and hoped that the covered entities would have considerable flexibility in determining the annual fuel consumption. The following is but one example of the complications of determining fuel use. For many solid fuel fired units, such as stoker coal fired boilers and pulverized coal fired boilers utilizing volumetric coal feeders, there is no way to measure weight rate of coal feed to the boilers. In those cases, alternative methods of determining heat input and annual fuel consumption need to be used. For example, the Tier 2 methodology for MSW fired units allows for use of boiler steam output and the maximum rated heat input to design steam output ratio to determine heat input. A similar approach could also be used for other solid fuel fired units. Similarly, in cases where byproduct fuels are fired or co-fired, the covered entity should have latitude to utilize any methods appropriate for the unit that provide representative determination of CO_2 emissions. Providing flexibility in fuel consumption determination methodology will decrease the cost of the reporting program with an insignificant impact on overall emissions accounting accuracy. It is assumed that this is EPA's intention based on the reference to relying on company records.

Response: EPA acknowledges the commenter's concerns, and has defined the term "company records" in §98.6 of the final rule. EPA believes that the revised definition provides appropriate guidance as to what records a facility may use to determine fuel consumption.

Commenter Name: Leslie Bellas
Commenter Affiliation: National Lime Association (NLA)
Document Control Number: EPA-HQ-OAR-2008-0508-0520.1
Comment Excerpt Number: 32

Comment: 40 C.F.R. 98.33 does not specify whether solid fuel calculations should use throughputs for "dry" or "as received" fuel. 40 C.F.R. 98.33(a) should be revised to specify that all fuel calculations should use dry solid fuel throughputs for consistency and more accurate results.

Response: EPA believes that fuel high heating value calculations should be done on an as-received basis, and that no additional language is necessary in the rule to clarify this.

Commenter Name: Leslie Bellas
Commenter Affiliation: National Lime Association (NLA)
Document Control Number: EPA-HQ-OAR-2008-0508-0520.1
Comment Excerpt Number: 21

Comment: The proposed definition of "continuous emissions monitoring system" (CEMS) in 40 C.F.R. §98.6 includes those systems that have a gas monitoring system or only a flow monitor. The definition of CEMS is significant because facilities with CEMS are required to use the Tier 4 calculation methodology. The Proposed Rule's definition of CEMS is overbroad in that it could be interpreted to include those facilities that only have a flow monitor or an in-situ monitor. In-situ systems are used to monitor pollutant gases in the stack without extracting a stack gas sample. These systems are mounted on the stack and are typically designed to monitor one pollutant per monitor. Upgrading these systems to monitor other pollutants is not mechanically possible for many of these systems, especially since different pollutants can require different methods of detection. Sources with in-situ systems that are required to monitor CO_2 could be required to remove the monitor from the stack and send it off-site for upgrades and calibration, which in the case of at least one of our members would take a minimum of three months. This would result in the source violating the Title V permit requirements to maintain and operate the monitor for the original pollutant. In the Preamble, Tier 4 requirements are based on the source's ability to use the existing CEMS equipment or perform "an appropriate upgrade of the existing CEMS." The Preamble does not refer to installing a new system, as would be required for many facilities that have in-situ monitors and not gas extraction monitors. This leads NLA to conclude that Tier 4 requirements are based on a source's ability to upgrade existing gas extraction systems by adding new monitoring components. The Proposed Rule's definition of CEMS is inconsistent with the definition of CEMS found in other EPA regulations, such as 40 C.F.R. §72.2. For example, the definition of CEMS in the Proposed Rule requires that readings be "recorded" every 15 minutes, while 40 C.F.R. Part 75 requires readings be "taken" every 15 minutes and the hourly average be recorded for compliance purposes. Incorporating different definitions in each EPA regulation to describe the same CEMS equipment will lead to confusion and error on the part of facility operators. The Proposed Rule's definition of CEMS should be revised to differentiate between monitors that can readily be upgraded to measure CO_2 and those that cannot. The Proposed Rule's definition of CEMS should be based on 40 C.F.R. §72.2, which provides that a CEMS is comprised of six component parts that sample, analyze, measure and provide a permanent record of emissions for specified pollutants. [Footnote: Continuous emission monitoring system or CEMS means the equipment required by part 75 of this chapter used to sample, analyze, measure, and provide, by readings taken at least once every 15 minutes, a permanent record of emissions, expressed in pounds per hour (lb/hr) for sulfur dioxide and in pounds per million British thermal units (lb/mmBtu) for nitrogen oxides. The following systems are component parts included in a continuous emission monitoring system: (1) Sulfur dioxide pollutant concentration monitor; (2) Flow monitor; (3) Nitrogen oxides pollutant concentration monitors; (4) Diluent gas monitor (oxygen or carbon dioxide); (5) A continuous moisture monitor when such monitoring is required by part 75 of this chapter; and (6) A data acquisition and handling system.] NLA's Proposal and Rationale: NLA proposes that the definition of CEMS in 40 C.F.R. §98.6 be revised as follows: Continuous emission monitoring system or CEMS means the total equipment required to sample, analyze, measure, and provide, by means of readings taken at least once every 15 minutes, a permanent record of emissions, expressed in pounds per hour (lb/hr) from stationary sources. The following systems are component parts included in a continuous emission monitoring system: (1) pollutant concentration monitor; (2) flow monitor; (3) diluent gas monitor when such monitoring is required by part 75 of this chapter, part 60 of this chapter, or an applicable State continuous monitoring program; (4) a continuous moisture monitor when such monitoring is required by part 75 of this chapter, part 60 of this chapter, or an applicable State continuous monitoring program; and (5) a data acquisition and handling system. NLA proposes that 40 C.F.R. §98.33(b)(5)(ii)(E) be revised to state: The installed CEMS include a gas monitoring system that has been certified in accordance with the requirements of part 75 of this chapter, part 60 of this chapter, or an applicable State continuous monitoring program and is either capable of measuring CO_2 in pounds per hour, or physically capable of being upgraded to measure CO_2 in pounds per hour, in accordance with the requirements of part 75 of this chapter, part 60 of this chapter, or an applicable State continuous monitoring program. NLA's proposal is consistent with EPA's intent to require sources to make use of existing equipment and not impose substantial operational burdens by the need to add an entire gas extraction system. See Preamble, 74 Fed. Reg. at 16,483 (looking for an appropriate upgrade of the CEMS).

Response: EPA disagrees with the commenter's request. The Tier 4 CEMS requirement is limited to larger solid fossil fuel units with an existing pollutant CEMS or volumetric flow rate monitor. EPA is requiring the use of CEMS due to the complexity of monitoring solid fuel consumption and the heterogeneous nature of the solid fuels. Many of these fossil-fuel fired units with a pollutant CEMS have an existing diluent monitor (O_2 or CO_2) that can be used to determine CO_2 emissions. Regarding Tier 4 applicability, EPA has revised the rule to clarify that all six criteria specified in §98.33(b)(4), subparagraphs (A) through (F), must be met before Tier 4 is required. Among these criteria is the requirement that the installed CEMS include a gas monitor of any kind or a stack gas volumetric flow rate monitor, or both and the monitors have been certified, either in accordance with the requirements of 40 CFR Part 75, Part 60 of this chapter, or an applicable State continuous monitoring program. With respect to the timing for meeting the Tier 4 requirements, EPA refers the commenter to §98.33(b)(5)(ii) which allows a facility until January 1, 2011 to begin reporting according to the Tier 4 methodology, if all of the monitors needed to measure CO_2 mass emissions have not been installed and certified by January 1, 2010. In this case, a facility may use Tier 2 or Tier 3 to report GHG emissions for 2010

Commenter Name: Leslie Bellas
Commenter Affiliation: National Lime Association (NLA)
Document Control Number: EPA-HQ-OAR-2008-0508-0520.1
Comment Excerpt Number: 30

Comment: The formulae set forth in 40 C.F.R. §98.33(e)(2) regarding how CEMS are used to calculate CO_2 emissions from the combustion of biomass or biomass-derived fuel is inappropriate for sources, such as lime plants that have process emissions. The proposed formula assumes that if one was to subtract the volume of CO_2 from fossil fuel combustion from the total volume of CO_2, then the remaining CO_2 would be biogenic. In the case of the lime industry, the difference between total and combustion emissions would be comprised of biogenic and process emissions. NLA proposes that the following equation be added to 40 C.F.R. §98.33(e)(2) to account for sources with process emissions: Total CO_2 tons – Fossil Fuel CO_2 tons – Process CO_2 tons = Biogenic Fuel CO_2 tons.

Response: EPA acknowledges the concerns and refers the commenter to §98.33(e)(2)(iv) where it is stated that if a CEMS is being used to measure the combined combustion and process emissions from a unit that is subject to another subpart of Part 98, then also subtract CO_2 process emissions from total CO_2 emissions to determine biogenic CO_2 emission.

Commenter Name: Laurie Burt
Commenter Affiliation: Massachusetts Department of Environmental Protection
Document Control Number: EPA-HQ-OAR-2008-0508-0453.1
Comment Excerpt Number: 36

Comment: 98.36(c)(1) EPA allows for grouping of small units. Massachusetts suggests that EPA specify that sources must use the same tier calculation methodology for a set of grouped units for a particular type of fuel combusted.

Response: EPA agrees with the comment, and has added language to §98.36(c)(1), clarifying that aggregated units must use the same tier for any common fuel(s) that they combust.

Commenter Name: Leslie Bellas
Commenter Affiliation: National Lime Association (NLA)
Document Control Number: EPA-HQ-OAR-2008-0508-0520.1
Comment Excerpt Number: 27

Comment: The formulae set forth in 40 C.F.R. §§98.33(a)(2)(iii) and 98.33(c) regarding the methods for calculating emissions from the combustion of municipal solid waste ("MSW") do not apply to lime plants. The formulae assume MSW is used to produce steam, but lime plants do not typically produce steam from burning MSW. NLA proposes the following formulae to calculate emissions from "non-steam" producing facilities: Eq. C-2b would be $CO_2 = 1 \times 10^{-3}$ *(EF)*$(Fuel)_p$*$(HHV)_p$. Eq. C-10b would be CH_4 or $N_2O = 1 \times 10^{-3}$ *(EF)*$(Fuel)_p$*$(HHV)_p$. $(Fuel)_p$ and $(HHV)_p$ would use the same definition as Eq. C-2a and C-10a.

Response: EPA has revised the rule so that Tier 1 may be used for a unit burning municipal solid waste that does not produce steam, provided that Tier 4 is not required. A default CO_2 emission factor and heat content for municipal solid waste has been added to Table C-1 for this purpose. Also in the final rule, default factors for municipal solid waste are provided in the revised Table C-2, therefore reporting of CH_4 and N_2O emissions is required.

Commenter Name: Linda Farrington
Commenter Affiliation: Eli Lilly and Company (Lilly)
Document Control Number: EPA-HQ-OAR-2008-0508-0680.1
Comment Excerpt Number: 26

Comment: Upon review of the Preamble, proposed rule §98.33(b), and the Subpart C Fact Sheet, Lilly noticed several inconsistencies that make it very difficult to determine when the Tier 4 emission calculation methodology is required and when it is optional. Lilly believes the decision tree in the Subpart C Fact Sheet can be a very useful tool, provided it is consistent with the language in the rule itself. Lilly offers the following suggestions for improving the language in §98.33(b)(5). a. The final rule should not require CO_2 CEMS (Tier 4) on a stationary combustion source merely because another type of CEMS (e.g., TOC, NO_x, CO) already exists. Lilly believes the use of fuel flow measurement and fossil fuel emission factors provide emission estimates of sufficient accuracy for a reporting rule. The use of Tier 4 should not be required, but included as a voluntary emission methodology for units that may have existing CO_2 CEMS. At a minimum, the Tier 4 methodology should only be required for very large solid fuel combustion sources (e.g. > 250 mmBTU/hr). b. An applicability table, similar to the one included in the Preamble, should be incorporated into the final rule. c. The criteria listed in §98.33(b)(5)(ii) and (iii) should include the words "AND" or "OR" as appropriate to clearly convey the Agency's intent with respect to multiple applicability criteria. Is Tier 4 required only if a unit meets all of the listed criteria? Or is Tier 4 required whenever a unit meets any one of the criteria listed?

Response: EPA acknowledges the commenter's concerns regarding Tier 4 applicability. EPA has revised the rule to clarify that all six criteria specified in subparagraphs (A) through (F) must be met before Tier 4 is required. However, EPA disagrees with suggestions that Tier 4 should only be required if the installed CEMS includes a CO_2 monitor. The Tier 4 CEMS requirement is limited to larger solid fossil fuel units with an existing pollutant CEMS or volumetric flow rate monitor. EPA is requiring the use of CEMS due to the complexity of monitoring solid fuel consumption and the heterogeneous nature of the solid fuels. Many of these fossil-fuel fired units with a pollutant CEMS have an existing diluent monitor (O_2 or CO_2) that can be used to determine CO_2 emissions. EPA's estimates of monitoring costs are averages for a representative facility and may not represent the actual cost in individual circumstances.

Commenter Name: Keith A. Nagel
Commenter Affiliation: ArcelorMittal USA and Severstal North America
Document Control Number: EPA-HQ-OAR-2008-0508-0496.1
Comment Excerpt Number: 26

Comment: Section 98.33(b)(5) requires clarification. Specifically, this section should be amended to clearly provide that all six criteria set forth in subsections (A) - (F) must be met to trigger obligatory Tier 4 monitoring. Although this section was apparently meant to establish a six-part test for triggering Tier 4 monitoring, as currently drafted, the six requirements are stated independently. The Preamble is also unclear on this point. While most of the relevant Preamble text apparently assumes that sources must meet all six criteria to trigger Tier 4 monitoring, it also contains the unqualified statement that "[t]he Tier 4 method, and the use of CEMS (with any required monitor upgrades), is required for solid fossil fuel-fired units with a maximum heat input capacity of greater than 250 mmBtu/hr. . . ." 74 Fed. Reg. at 16483. EPA should clarify §98.33(b)(5) by inserting semicolons between each lettered requirement (instead of periods) and by adding the word "and" after §98.33(b)(5)(E). The Preamble to the final rule should also expressly acknowledge this clarification and confirm that all six requirements must be met before any obligation for Tier 4 monitoring accrues.

Response: EPA acknowledges the commenter's concerns regarding Tier 4 applicability. EPA has revised the final rule to clarify that all six criteria must be met before Tier 4 is required.

Commenter Name: Leslie Bellas
Commenter Affiliation: National Lime Association (NLA)
Document Control Number: EPA-HQ-OAR-2008-0508-0520.1
Comment Excerpt Number: 25

Comment: To the extent that sources are required to install CEMS, they should have sufficient time to install and certify the equipment. The requirement in 40 C.F.R. §98.33(b)(6)(ii) to install and certify CEMS by January 1, 2011 may not be achievable given the need to select, deliver, engineer, and install and certify the equipment. Installation of CEMS may also be delayed due to the potential for increased demand for equipment and stack testing consultants created by this nationwide GHG reporting rule. Revise 40 C.F.R. §98.33(b)(6)(ii) to require installation and certification of CEMS by January 1, 2012.

Response: The final rule requires data collection for calendar year 2010, but has been changed since proposal to allow the use of best available monitoring methods for the first part of 2010. EPA acknowledges the concerns of the commenters and has clarified the rule for those units that must upgrade their existing CEMS to meet Tier 4 requirements. If all the monitors needed have not been installed and certified by January 1, 2010, they may use either Tier 2 or 3 in 2010.

Commenter Name: Keith Adams
Commenter Affiliation: Air Products and Chemicals, Inc.
Document Control Number: EPA-HQ-OAR-2008-0508-1142.1
Comment Excerpt Number: 24

Comment: The proposed rule offers an equation for calculating the contribution of CO_2 emissions from flue gas desulfurization sorbents, equation C-11, which does not appear to be dimensionally (units) correct. Specifically, the "R" term in the equation appears to be incorrectly defined. Insure the definitions of terms for equation C-11 are dimensionally correct.

Response: EPA has corrected this error in the final rule. The R term has been redefined as "1.00, the calcium-to-sulfur stoichiometric ratio."

Commenter Name: Leslie Bellas
Commenter Affiliation: National Lime Association (NLA)
Document Control Number: EPA-HQ-OAR-2008-0508-0520.1
Comment Excerpt Number: 23

Comment: The method to calculate hourly emissions proposed in 40 C.F.R. §98.33(a)(4)(v), Equations C-6 and C-7, and 40 C.F.R. §98.33(e)(2)(i), Equation C-12, appears to be inconsistent with Part 75, and may understate emissions during partial hours of operation. The rule requires sources to calculate the mass and volume of CO_2 emitted each hour by multiplying the CO_2 emission rates and hourly flow rates by the fraction of the hour that the source was in operation. Because the downtime will already be accounted for in the "hourly average emission rate," or "hourly average CO_2 concentration," there is no need to multiply the hourly average by operating time for that hour. The "Example of EPA's Proposed Tier 4 CO_2 Emissions Calculation Method" demonstrates that the proposed calculation method understates the emissions for any partial hours of operating time. [See Attachment 7 of DCN: EPA-HQ-OAR-2008-0508-0520.1 for example of Tier 4 calculation] Revise 40 C.F.R. §98.33(a)(4)(v), Equations C-6 and C-7, and 40 C.F.R. §98.33(e)(2)(i), Equation C-12 to delete the requirement to multiply CO_2 emission rates and hourly flow rates by the fraction of the hour that the source was in operation. NLA proposes that total emissions be calculated by summing the hourly averages during operating times throughout the year to be consistent with Parts 60 and 75.

Response: EPA appreciates your support and thanks you for your comment. The discrepancy has been reconciled in the final rule.

Commenter Name: Dan F. Hunter
Commenter Affiliation: ConocoPhillips Company
Document Control Number: EPA-HQ-OAR-2008-0508-0515.1
Comment Excerpt Number: 23

Comment: The regulatory language (98.33(b)(5))does not clearly communicate the criteria requiring Tier 4 methodology. The Preamble discussion does a much better job clarifying the requirements. According to the Preamble, Tier 4 is required for: 1. Units with a maximum rated heat input capacity of greater than 250 mmBtu/hr, or greater than 250 tons/day of MSW, AND 2. The unit combusts solid fuel or MSW, AND 3. The unit has operated for more than 1,000 hours in any calendar year since 2005, AND 4. The Unit has installed CEMS that are required by an applicable federal or state regulation or the unit's operating permit. Add clarification to §98.33(b)(5)(ii)(D) and (E) to indicate whether the "installed CEMS" are any type of CEMS (i.e. criteria pollutant CEMS or CO_2 CEMS) or a specific type of CEMS (e.g. CO_2 CEMS). ConocoPhillips recommends changing the regulatory language to clearly describe the conditions requiring the use of Tier 4 methodology.

Response: EPA acknowledges the commenter's concerns regarding Tier 4 applicability. EPA has revised the rule to clarify that all six criteria must be met before Tier 4 is required. EPA has also clarified that "the installed CEMS include a gas monitor of any kind or a stack gas volumetric flow rate monitor, or both…"

Commenter Name: Leslie Bellas
Commenter Affiliation: National Lime Association (NLA)
Document Control Number: EPA-HQ-OAR-2008-0508-0520.1
Comment Excerpt Number: 31

Comment: Tables C-1 and C-2 in 40 C.F.R. §98.33 do not contain default values for landfill gas. NLA proposes that landfill gas should be added to tables C-1 and C-2 in 40 C.F.R. §98.33 so that a facility using landfill gas can use Tiers 1 or 2 for calculating emissions. The use of landfill gas as fuel prevents the release of methane to the atmosphere, and should be encouraged.

Response: EPA has added landfill gas to Table C-1 as "Biogas (Captured methane)."

Commenter Name: Traylor Champion
Commenter Affiliation: Georgia-Pacific, LLC (GP)
Document Control Number: EPA-HQ-OAR-2008-0508-0380.1
Comment Excerpt Number: 21

Comment: Tier 4 adjustment for biogenic fuels must be improved. If EPA ultimately decides to retain current Tier 4 methodology as presented in the proposed rule, the adjustment required for combination boilers firing both fossil and biofuels should be modified to allow the use of the Tier 1 calculation methodology for biogenic CO_2 emissions rather than using an annual F-factor adjustment for the fossil fuel component. EPA has allowed the use of Tier 1 methodology for calculation of CO_2 from biomass and other biogenic fuels from all sizes of combustion units and it seems logical that this same methodology should be used to determine the CO_2 emissions from combination boilers that fire solid fossil fuel and biogenic fuels. Reporters would then only have to subtract the amount of biogenic CO_2 from the amount of total CO_2 determined by the CEMS and flow meter to obtain that portion of emissions resulting from combustion of fossil fuels. Estimation of emissions using a fossil fuel F-factor and amount of fossil fuel burned merely to determine the amount of biogenic fuel seems unnecessarily complex when a straightforward calculation of the biogenic fuel is available. In the Technical Support Document for the Pulp and

Paper Sector (P&P TSD), EPA outlines a Tier 5 methodology to be used to determine biogenic CO_2 emissions when a CEMS is in place on a boiler co-firing biomass and fossil fuels. However, this methodology is excluded from the rule. EPA should specifically identify and allow for use of the Tier 5 method for combination boilers co-firing biomass and fossil fuels within the rule language itself.

Response: In the Technical Support Document for Subpart AA Pulp and Paper Plants, EPA requested comment on using a fuel-steam balance approach to calculate CO_2 emissions from biogenic fuels. EPA has received numerous comments endorsing this approach, particularly with the use of biogenic fuels.

While EPA has allowed the use of Equation C-1 (Tier 1) to calculate biogenic CO_2 emissions where the biomass consists of wood, wood waste, or other biomass-derived solid fuels (see Table C-1), and the mass of biogenic fuel combusted can be accurately quantified, and the use of Tier 2 methods for certain gaseous and liquid biofuels, EPA does not believe that these methods are appropriate for all situations where biogenic fuels are combusted. Because of the variability of certain types of biofuels, EPA believes that it may be more appropriate to quantify biogenic emissions from combination boilers using fossil fuel F-factors and the amount of fossil fuel burned. EPA believes that the method provided in §98.33(e) is sufficient for calculating biogenic emissions from combination boilers, and that it is not necessary to include the Tier 5 methods from the Pulp and Paper TSD. However, EPA has added some flexibility to §98.33(e): the use of ASTM Methods D7459-08 and D6866-06a to determine biogenic CO_2 emissions has been expanded to include the combustion of other biogenic fuels besides municipal solid waste. The commenter should also consult §98.33(e)(6) and Equation C-15 for an additional option specifically targeted to the pulp and paper industry.

Commenter Name: Traylor Champion
Commenter Affiliation: Georgia-Pacific, LLC (GP)
Document Control Number: EPA-HQ-OAR-2008-0508-0380.1
Comment Excerpt Number: 20

Comment: Tier 2 requirement of monthly HHV and Tier 3 requirement of monthly carbon content testing is unnecessary. The monthly measured HHV requirement of the Tier 2 calculation methodology and the monthly measured carbon content requirement of Tier 3 are unnecessary and costly. As noted above, over the years industry has developed a large body of data on HHV and emission factors for common fossil fuels, and additional testing of HHV and carbon contents will not improve that database further. If default emission factors and HHVs are given in Tables C-1 or C-2, reporters should be able to use these data for the entire facility regardless of the size and type of the individual combustion unit. Where these data are not given in Tables C-1 or C-2, reporters should be allowed to develop a "facility-specific default" value for the particular parameter for use in calculating emissions. Monthly measurements are excessive, costly, and unnecessary.

Response: The mandatory monthly fuel sampling and analysis requirements for traditional fossil fuels have been relaxed for Tiers 2 and 3. EPA agrees with the commenters that for a homogeneous fuel such as pipeline natural gas, monthly sampling is not necessary. For other fuels such as oil and coal, which are delivered in shipments or lots, requiring monthly sampling may be impractical; new fuel lots or deliveries may not be received on a monthly basis. Therefore, §98.34 has been revised to require that natural gas be sampled semiannually. For fuel oil and coal, a representative sampling is required for each fuel lot, i.e., for each shipment or delivery. For other liquid fuels and biogas, quarterly sampling is required. For other solid fuels, excluding municipal solid waste, weekly composite sampling with monthly analysis is required. For other gaseous fuels, the daily sampling requirement has been retained, but only for facilities with existing equipment in place that is capable of providing the data. Otherwise, weekly sampling is required, which may be postponed in favor of monthly sampling until 2011 if new equipment must be purchased or if existing equipment must be upgraded to meet the weekly sampling and analysis requirements.

The final rule clarifies that fuel sampling and analysis data provided by the supplier may be used in the emission calculations, and that fuel billing meters may be used to quantify fuel consumption. To simplify the emission calculations in Tiers 2 and 3, averaging of HHV and carbon content data is permitted if these data are obtained at least at the minimum frequency specified in §98.34. If the results of fuel sampling are received monthly or more frequently, the weighted annual average high heat value shall be calculated using Equation C-2b. If the results of fuel sampling are received less frequently than monthly, then the annual average HHV shall be calculated using the arithmetic average HHV for all valid samples for the year. However, regardless of the sampling frequency, the owner or operator must use the results of all available valid fuel analyses in the emissions calculations.

Commenter Name: Angela Burckhalter
Commenter Affiliation: Oklahoma Independent Petroleum Association (OIPA)
Document Control Number: EPA-HQ-OAR-2008-0508-0386.1
Comment Excerpt Number: 20

Comment: In the proposed rule, under Subpart C, it is confusing as to which Tier calculation method a reporter should use. In the Preamble, EPA provides Table C-1 that clearly outlines which method is to be used based on the fuel being used and the combustion unit size. We recommend that this Preamble Table be included in the rule to clearly outline what calculation method is to be used.

Response: EPA acknowledges the commenter's concerns, and has substantially revised §98.33(b) in the final rule, relaxing tier and calculation method applicability. Though EPA has not incorporated a table such as Table C-1 from the Preamble into the final rule, the Agency believes that the revised language makes it clear which Tier calculation method(s) a reporter may use. The revised rule also adds considerable flexibility, allowing more reporters to use the lower tiers.

Commenter Name: Niki Wuestenberg
Commenter Affiliation: Republic Services, Inc.
Document Control Number: EPA-HQ-OAR-2008-0508-0557.1
Comment Excerpt Number: 15

Comment: Republic request clarification on EPA's requirement of using the Tier 4 calculation under s. 98.33(b)(5)(ii). Currently this section would require the use of Tier 4 calculation of a unit if any of the 6 subheadings meet the requirements. This is concerning because it will impact all landfill gas projects in the U.S. Specifically landfill gas to energy projects would be impacted under the subheading (C) of this section if a unit has operated for more than 1,000 hours in any calendar year since 2005 and would therefore be required to perform a Tier 4 calculation. This would require installing continuous emissions monitoring equipment on all the stacks of each emission unit which is currently not required under existing permits for these facilities. We believe existing regulations under the NSPS JJJJ which require performance testing on stationary electrical generation engines at an interval of every 8760 hours or 3 years of operation is sufficient testing. Further these emissions are from a biogenic source which we believe should not be included as stated previously. The ability for these sources to install the necessary equipment by 2011 will be difficult and an unnecessary burden.

Response: EPA acknowledges the commenters' concerns regarding Tier 4 applicability, and has revised the rule to clarify that all six criteria must be met before Tier 4 is required. The commenter is also referred to §98.33(b) which allows for the use of Tier 1 methodology for a unit of any size, provided that the fuel is exclusively solid, gaseous, or liquid biomass fuels listed in Table C-1

The final rule requires data collection for calendar year 2010, but has been changed since proposal to allow use of best available monitoring methods for the first part of 2010.

Commenter Name: Steven D. Meyers
Commenter Affiliation: General Electric Company (GE)
Document Control Number: EPA-HQ-OAR-2008-0508-0532.1
Comment Excerpt Number: 15

Comment: GE has found confusing regulatory language at Section 98.33(b)(5)(ii) that lists the circumstances under which the Tier 4 calculation methodology (CEMS) must be used at fuel combustion sources, which are listed in sub-paragraphs A – F. The proposal does not indicate whether these sub-paragraphs apply together or separately. Because absurd results would occur if each paragraph represented an independent circumstance for which CEMS would be required, and because the word "or" does not appear, GE assumes that EPA intends CEMS to be required only if all of the circumstances are present. For example, if each sub-paragraph indicated an independent requirement for CEMS, a CEMS would apply to any fuel combustion unit of any size if it operated for more than 1,000 hours per year. Including Table C-1 in the finally promulgated rule would help but clearness in the language is paramount.

Response: EPA acknowledges the commenter's concerns regarding Tier 4 applicability. EPA has revised the rule to clarify that all six criteria must be met before Tier 4 is required.

Commenter Name: Michael E. Van Brunt
Commenter Affiliation: Covanta Energy Corporation
Document Control Number: EPA-HQ-OAR-2008-0508-0548.1
Comment Excerpt Number: 14

Comment: In §98.33(b)(6)(ii), the Proposed Rule allows Tier 3 methods to be used until 2011 for those facilities that will need to add CO_2 and/or flow CEMS in order to comply with the regulation. The Tier 3 methodology requires monthly direct measurements of fuel carbon content, which would require extremely large samples in order to be representative for MSW. The Tier 2 methodology, already accepted for smaller MSW units, should be allowable in the interim. Furthermore, given the expected date of release of the final regulation, we propose that interim reporting be allowed up to the 2012 inventory year.

Response: The final rule requires data collection for calendar year 2010, but has been changed since proposal to allow use of best available monitoring methods for the first part of 2010. EPA acknowledges the concerns of the commenters, and has clarified the rule for those units that must upgrade their existing CEMS to meet Tier 4 requirements. If all the monitors needed have not been installed and certified by January 1, 2010, they may use either Tier 2 or 3 in 2010.

Commenter Name: Lloyd Stone
Commenter Affiliation: Westlake Chemical Corporation
Document Control Number: EPA-HQ-OAR-2008-0508-0442.1
Comment Excerpt Number: 12

Comment: 98.34(c) and (d): Affected sources should have the ability to use a gas chromatograph to calculate the carbon content and molecular weights just as it is allowed in §98.244(b)(3).

Response: EPA agrees with the comment and has added the option to determine HHV, carbon content, and molecular weight of gaseous fuels using chromatographic analysis. See §98.34 of the final rule.

Commenter Name: Kerry Kelly
Commenter Affiliation: Waste Management (WM)
Document Control Number: EPA-HQ-OAR-2008-0508-0376.1
Comment Excerpt Number: 40

Comment: 98.33(e)(3) MSW Combustion - The calculations for MSW combustion focus on biogenic CO_2 which is not considered a GHG gas by IPCC or in any GHG reporting convention as explained above on our Section VI. Non-biogenic CO_2 or Anthropogenic only is included in total CO_2e emissions. Since only non-biogenic CO_2 is included in CO_2e total, Section 98.33(e)(5) should be revised to include calculation of non-biogenic CO_2 emissions derived from ASTM D7459-08 and D6866-06a methods. Non-biogenic fraction is 1- biogenic fraction as reported with ASTM D6866 results. If biogenic or biomass fraction is 0.30 then non-biogenic fraction in 1- 0.30 or 0.70. Note also the biogenic fraction of 0.30 used in the example is incorrect. The national biogenic CO_2 average fraction for MSW combustion is approximately 60 - 70% (or 0.60 - 0.70).

Response: See the response to comment EPA-HQ-OAR-2008-0508-0690.1 excerpt 1 corresponding to Section II. of the Preamble, and the response to comment EPA-HQ-OAR-2008-0508-0631.1 excerpt 71 corresponding to Subpart C for additional explanation of the reporting of biogenic CO_2 emissions.

EPA has not revised the calculation method for biogenic/non-biogenic fractions. The end result is the same in either case.

Commenter Name: Rechelle Holloway
Commenter Affiliation: Tyson Foods, Inc.
Document Control Number: EPA-HQ-OAR-2008-0508-0379.1
Comment Excerpt Number: 11

Comment: As with annual emission inventories or air construction and operating permits, most emissions rates submitted are based off of AP-42 or FIRE emissions factors derived either fuel/unit specific or process specific. The emission factors for GHG pollutants currently come from the same locations as criteria pollutant emissions factors. The derived emissions factors have been used as a means of determining state emission fees as well as allowing facilities to obtain PSD permits. If these derived factors have been good enough to sustain the environment and in many cases used as a means to continue to improve the environment then the GHG emission factors should sustain the reporting requirements as well. Over time as facilities are required to further show compliance through potential permitting, stack testing can be requested and better data developed. EPA has no basis to consider that the existing emission factors are not worthy of use at this time.

Response: For consistency in reporting to this rule, EPA requires the use of the tier methods for calculating CO_2 based on unit size and fuel type combusted. The default emission factors provided by EPA have been developed for the national greenhouse gas inventory and other greenhouse gas programs. EPA believes that its approach is consistent with the objective of this program to collect consistent greenhouse gas data from all affected reporters.

Commenter Name: Gary Moore
Commenter Affiliation: Pensacola Plant of Ascend Performance Materials LLC
Document Control Number: EPA-HQ-OAR-2008-0508-0366.1
Comment Excerpt Number: 7

Comment: Should the Agency determine that site specific emission factors are required to be determined for any fuels not listed in Table C-3, more specific guidance must be provided rather than "subject to the approval of the Administrator, develop site-specific CH_4 and N_2O emission factors, based on the results of source testing." Stack testing is expensive and some older boilers may not have stack sampling facilities installed making it potentially difficult for what the Agency acknowledges as relatively small emissions on a CO_2e basis. Guidance on what the Administrator would be looking for and methodologies to employ when having to deal with co-firing of fuels due to technical (such as off gases being introduced into a boiler or other combustion device that do not independently supporting combustion) or permitting issues.

Response: In response to the comment, EPA has revised the default emission factors needed to calculate CH_4 and N_2O emissions, adding many of the emission factors suggested by commenters. EPA has also clarified in the final rule that only CH_4 and N_2O emissions from combustion of those fuels listed in Table C-2 (formerly C-3) of Subpart C are required to be reported. Further, reporting of CH_4 and N_2O emissions is not required for fuels that are used exclusively for unit startup or ignition.

Commenter Name: Paul Dubenetzky
Commenter Affiliation: KERAMIDA Inc.
Document Control Number: EPA-HQ-OAR-2008-0508-0419.1
Comment Excerpt Number: 6

Comment: Reconcile the difference in the CO_2 emission factor for #2 fuel oil combustion of 73.1 kg CO_2/mmBtu listed in 40 CFR 98, Subpart C, Table C-1 (74 FR 16640) with TCR's emission factor of 73.15 kg CO_2/mmBtu as found in the TCR's General Reporting Protocol v.1.1 Table 12.1 U.S. Default Factors for Calculating CO_2 Emissions from Fossil Fuel Combustion: (http://www.thecli.m.ateregistry.org/d.ownloads/GRP.pdf).

Response: Tables C-1 and C-2 provide emission factors. In determining factors, EPA has used the general approach of assigning emission factors based on higher heating values of the fuels. EPA has taken default emission factors from the U.S. inventory or the IPCC, and refers the commenter back to TCR for an explanation of the source of data provided in that program.

Commenter Name: Gary Moore
Commenter Affiliation: Pensacola Plant of Ascend Performance Materials LLC
Document Control Number: EPA-HQ-OAR-2008-0508-0366.1
Comment Excerpt Number: 5

Comment: Should off gas burned in control devices and residue removed in burnout furnaces be determined to be fuels under the rule, the proposed rule needs to clarify emission factors for CH_4, and N_2O. Currently in §98.33(c)(4) reads: "If, for a particular type of fuel, default CH_4 and N_2O emission factors are not provided in Table C-4 of this subpart, the owner or operator may, subject to the approval of the Administrator, develop site-specific CH_4 and N_2O emission factors, based on the results of source testing." The use of the word "may" in the proposed rule introduces some ambiguity as to the intent of this paragraph. In the Preamble to the rule on page 16485 it states: "As described previously, EPA is allowing simplified emissions calculation methods for CH_4 and N_2O. The annual CH_4 and N_2O emissions would be estimated using EPA-provided default emission factors and annual heat input values." "A CEMS methodology was not selected for measuring N_2O primarily because the cost impacts of requiring the installation of CEMS is high in comparison to the relatively low amount of N_2O emissions (even on a CO_2e basis) that would be emitted from stationary combustion equipment." The amount of "other" types of fuels combusted on a national level is likely to be small relative to the amount of listed fuels and with the Agency acknowledging that for stationary combustion CH_4 and N_2O emissions are small relative to CO_2 emissions does this mean that the Agency makes reporting the CH_4 and N_2O emissions optional? If emissions are required to be reported, the Agency could propose the use of emission factors from the fuel closest to the "other" fuel being combusted to estimate the CH_4 and N_2O emissions.

Response: EPA has clarified in the final rule that only CH_4 and N_2O emissions from combustion of those fuels with default factors listed in Table C-2 (formerly C-3) of Subpart C are required to be reported. Further, reporting of CH_4 and N_2O emissions is not required for fuels that are used exclusively for unit startup or ignition.

Commenter Name: Paul Dubenetzky
Commenter Affiliation: KERAMIDA Inc.
Document Control Number: EPA-HQ-OAR-2008-0508-0419.1
Comment Excerpt Number: 5

Comment: With respect to General Stationary Fuel Combustion, KERAMIDA suggests that the U.S. EPA: 1. Maintain the rule's general approach of assigning emission factors to fuels based on their heat value or carbon content and not based on the type of equipment the fuel is combusted (40 CFR 98, Subpart C, Table C-1, 74 FR 16639).

Response: In response to the comment, EPA appreciates the consideration given to the general approach of assigning emission factors based on higher heating values of the fuels. EPA has maintained this approach and these emission factors appear in Table C-1 and C-2.

Commenter Name: Laurie Zelnio
Commenter Affiliation: Deere & Company
Document Control Number: EPA-HQ-OAR-2008-0508-0355.1
Comment Excerpt Number: 3

Comment: Deere submitted a question to the EPA regarding the requirement to use a CEMS to calculate carbon dioxide (CO_2) emissions from stationary sources. We received a response to our inquiry that a facility must use CEMS to calculate CO_2 only if it meets all of the criteria in either 40 CFR §98.33(b)(5)(ii) or (iii). It is unclear whether the criteria in sections §98.33(b)(5)(ii) and (iii) are inclusive or exclusive of each other. There is no "and" or "or" after the conditions to determine the intent of the rule. For example, if a facility has a combustion unit less than 250 mmBtu/hr that combusts solid fuel and operates more than 1,000 hours a year but is not required to have CEMs equipment, is it required to use Tier 4 calculation methodology? Deere suggests the following revisions to address this question: (1) §98.33(b)(5)(ii) Shall be used for a unit if all of the conditions specified in paragraphs (b)(5)(ii)(A) through (F) are met. (2) §98.33(b)(5)(iii) ...if the unit meets all of the conditions specified in paragraphs (b)(5)(iii)(A) through (C).

Response: EPA acknowledges the commenter's concerns regarding Tier 4 applicability. EPA has revised the rule to clarify that all six criteria must be met before Tier 4 is required.

Commenter Name: Allen Kacenjar
Commenter Affiliation: Squire Sanders
Document Control Number: EPA-HQ-OAR-2008-0508-0492.1
Comment Excerpt Number: 3

Comment: The language of §98.33(b)(5) should be clarified to confirm that all six criteria must be met to trigger obligatory Tier 4 monitoring. Although this section was apparently meant to establish a six-part test for triggering mandatory Tier 4 monitoring, the six identified requirements are stated independently. The Preamble is also unclear on this point. While most of the relevant Preamble text apparently assumes that sources must meet all six criteria to trigger Tier 4 monitoring, it also contains the unqualified statement that "[t]he Tier 4 method, and the use of CEMS (with any required monitor upgrades), is required for solid fossil fuel-fired units with a maximum heat input capacity of greater than 250 mmBtu/hr. . . ." 74 Fed. Reg. at 16483. EPA should clarify §98.33(b)(5) by inserting semicolons between each lettered requirement (instead of periods) and by adding the word "and" after §98.33(b)(5)(E). It should also expressly confirm in the Preamble to the final rule that all six requirements must be met before any Tier 4 monitoring obligation accrues.

Response: EPA acknowledges the commenters' concerns regarding Tier 4 applicability. EPA has revised the rule to clarify that all six criteria must be met before Tier 4 is required.

Commenter Name: Louis Kollias
Commenter Affiliation: Metropolitan Water Reclamation District of Greater Chicago (District)
Document Control Number: EPA-HQ-OAR-2008-0508-0311
Comment Excerpt Number: 2

Comment: It is unclear why the US EPA is only using the HHV for the combusted fuels. The World Resource Institute's (WRI) Greenhouse Gas Protocol is the most widely used international accounting tool for government and business leaders to understand, quantify, and manage GHG emissions. In their calculations of stationary combustion sources, they use a similar approach to the US EPA; however, they consider an average of the lower heat value (LHV) and HHV. The US EPA's approach would therefore provide higher energy use calculations than the WRI's approach. The reason for only using the HHV in the US EPA-proposed ruling needs to be addressed.

Response: EPA believes that use of the HHV for fuel heat content is consistent with existing federal and state requirements for measuring and reporting emissions from stationary fuel combustion (SO_2, NO_x, particulate matter) and the Inventory of U.S. Emissions and Sinks. Averaging HHV and LHV as suggested by the commenter would add additional requirements and complexity.

Commenter Name: R. Siegel
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2008-0508-0151
Comment Excerpt Number: 1

Comment: For the different tiers of reporting, please change it to maximum hourly fuel input during the year, instead of installed nameplate. Some facilities have significantly more installed capacity than can physically be used at once, much of this is for redundancy.

Response: See the Premable, Section II. E., for a summary of comments and responses on thresholds. The Agency refers the commenter to the definition of "maximum rated heat input capacity" in §98.6 for further clarification.

Commenter Name: See Table 4
Commenter Affiliation:
Document Control Number: EPA-HQ-OAR-2008-0508-0455.1
Comment Excerpt Number: 12

Comment: The equations provided in Tier Three of proposed §98.33 for calculating annual CO_2 mass emissions for liquid and gas-fired combustion sources -- Equations C-4 and C-5 -- would only allow for fuel to be measured on a volume basis. This presumption, that liquid and gaseous fuel quantities are only measured on a volume basis, is false. Fuel flow meters may directly measure the volume or mass of the fuel combusted. Therefore, the Class of '85 believes the Agency should expand its annual CO_2 mass emissions formulas for liquid and gaseous fuels to account for fuel quantities measured using either type of fuel flow meter.

Response: EPA appreciates your comment and has added language to allow mass flow measurements for liquid fuels.

Commenter Name: Gary Moore
Commenter Affiliation: Pensacola Plant of Ascend Performance Materials LLC
Document Control Number: EPA-HQ-OAR-2008-0508-0366.1
Comment Excerpt Number: 11

Comment: Our reading of the requirement to use Tier 4 calculation methods for stationary combustion devices indicates that CEMS units are required for large units burning solid fuels meeting all of the requirements on §98.33(b)(5)(ii). Large units burning liquid or gaseous fuels would be allowed to use Tier 3 methods even if they met some of the requirements in §98.33(b)(5)(ii). This interpretation is consistent with both the Preamble and Technical support document. The rule language is difficult to interpret on this and we request that the rule language be clarified to confirm this.

Response: EPA acknowledges the commenter's concerns regarding Tier 4 applicability. EPA has revised the rule to clarify that all six criteria specified in subparagraphs (A) through (F) must be met before Tier 4 is required. Large units burning liquid or gaseous fuels are not required to use Tier 4.

Commenter Name: Leslie Bellas
Commenter Affiliation: National Lime Association (NLA)
Document Control Number: EPA-HQ-OAR-2008-0508-0520.1
Comment Excerpt Number: 52

Comment: 40 C.F.R. §§98.33(b)(5)(ii)(A)-(F) sets forth six conditions for use of the Tier 4 methodology by units with a maximum rated heat input capacity of greater than 250 mmBtu/hr. To clearly indicate that all six conditions must be met before requiring use of the Tier 4 emission calculation methodology, each condition in 40 C.F.R. §§98.33(b)(5)(ii)(A) - (F) should end with a semi-colon and that after the semi-colon in 40 C.F.R. §98.33(b)(5)(ii)(E), the word "and" should be added.

Response: EPA acknowledges the commenter's concerns regarding Tier 4 applicability. EPA has revised the rule to clarify that all six criteria must be met before Tier 4 is required.

Commenter Name: Laurie Burt
Commenter Affiliation: Massachusetts Department of Environmental Protection
Document Control Number: EPA-HQ-OAR-2008-0508-0453.1
Comment Excerpt Number: 35

Comment: 98.33(b)(5)(ii) lists when a source must use Tier 4 calculation method in subsections (A) through (F). Massachusetts asks EPA to clarify if they meant that this requirement applies to sources that meet all the requirements of (A) through (F), or any of the requirements of (A) through (F).

Response: EPA acknowledges the commenter's concerns regarding Tier 4 applicability. EPA has revised the rule to clarify that all six criteria must be met before Tier 4 is required.

Commenter Name: Laurie Burt
Commenter Affiliation: Massachusetts Department of Environmental Protection
Document Control Number: EPA-HQ-OAR-2008-0508-0453.1
Comment Excerpt Number: 34

Comment: 98.33(a)(4)(i) references use of certain monitors "except as otherwise provided in paragraph (a)(1)(iv)(D)." There is no paragraph (a)(1)(iv)(D) in section 98.33.

Response: EPA has corrected this error. The paragraph referenced in the comment (§98.33(a)(4)(i) in the final rule) now refers to section §98.33(a)(4)(iv).

Commenter Name: Traylor Champion
Commenter Affiliation: Georgia-Pacific, LLC (GP)
Document Control Number: EPA-HQ-OAR-2008-0508-0380.1
Comment Excerpt Number: 31

Comment: EPA should include a back calculation methodology to determine the amount of biomass combusted. EPA has proposed that biomass (wood, bark, etc.) being burned in a combustion device be done by Tier 1 methodology. This basically requires measurement of the amount of biomass being combusted, adjusting this amount to 12% moisture content (as currently specified in Table C-1) and then multiplying this result by the default HHV and emission factor listed in Table C-1. Most mill operations do not directly measure wood burned but rely on back calculation of the amount of wood combusted from steam generation rates and the heat design rate of the combustion device – a practice well-grounded in solid engineering principles and recognized by regional climate change initiatives such as the Western Climate Initiative (WCI) as well as Green-e, the nation's leading independent certification and verification program for renewable energy credits, which GP certifies at two mills – Port Hudson, LA and Toledo, OR. The methodology is also commonly used to determine Btu input for emission stack test reports in lieu of the F-factor methodology. During a May 28, 2009 meeting between representatives from EPA and Koch Industries Inc, GP provided a white paper detailing the calculation methodology employed at our facilities to determine the amount of biomass combusted from steam production data. [See DCN: EPA-HQ-OAR-2008-0508-0380.1 for paper attachment]. EPA's Technical Support Document for the Pulp and Paper Sector (P&P TSD) provides extensive detail on use of a back-calculation method to determine the quantity of biomass fuels fired from steam production data. GP agrees with EPA's statement in the P&P TSD that, "…given the variations in biomass fuels fired in a given boiler over time and the fact that biomass is co-fired with fossil fuels, obtaining site-specific HHV and biomass CO_2 emissions factors would be very difficult." As EPA acknowledges, the majority of biomass fired at pulp and paper mills is generated on-site; therefore, purchasing records are not available to determine the quantity of biomass consumed, nor are belt scales in use at some, but certainly not all, mills an accurate method for determining the amount of biomass fired due to varying moisture contents of the biomass. EPA details in the P&P TSD an alternate method for determining the total amount of biomass fired in a boiler by back-calculating the mass of biomass from annual steam production data, information on the other fuels combusted in a boiler, and the efficiency of biomass-to-energy conversion. However, EPA does not acknowledge this method in the Preamble or the rule and does not specifically allow for its use for biomass fuels. EPA should specifically allow a back calculation methodology for biomass such as the WCI method, EPA's method provided in the P&P TSD, and/or the method provided in the attached white paper as an option to using the Tier 1 methodology. EPA should list a default CO_2 emission factor for solid biomass fuels in Table C-2.

Response: Since default CO_2 emission factors are provided for several types of solid biomass fuels, including wood and wood residuals, agricultural byproducts, peat, and solid byproducts, in Table C-1, EPA does not believe that it is necessary to add an additional default factor. EPA has also extended the use of steam production and combustion unit efficiency to calculate CO_2 emissions to other solid fuels in addition to municipal solid waste. These parameters may be used to quantify the amount of biomass combusted in a unit.

Commenter Name: Traylor Champion
Commenter Affiliation: Georgia-Pacific, LLC (GP)
Document Control Number: EPA-HQ-OAR-2008-0508-0380.1
Comment Excerpt Number: 30

Comment: In light of EPA's parallel efforts to define "solid waste" for purposes of the Commercial and Industrial Solid Waste Incinerator (CISWI) and Boiler MACT rulemakings currently on remand, EPA should be sensitive to the possible inadvertent characterization of wood and other biomass-based materials as "waste" rather than "fuels." Accordingly, GP requests that EPA delete the reference to "wood waste" in Table C-1 since wood used as a fuel is not a waste, but rather a valuable commodity. EPA should replace this reference with the term "wood residuals."

Response: In response to the comment, EPA has replaced the language "wood waste" to read "wood residuals" in the Subpart C tables.

Commenter Name: Traylor Champion
Commenter Affiliation: Georgia-Pacific, LLC (GP)
Document Control Number: EPA-HQ-OAR-2008-0508-0380.1
Comment Excerpt Number: 29

Comment: Impregnated sawdust is currently listed as a distinct fuel in Table C-2, which does not provide default HHVs. However, impregnated sawdust is actually a residual biomass from the manufacture of wood products such as plywood, oriented strand board and fiberboard. These materials fit into the proposed definition of biomass: Biomass means non-fossilized and biodegradable organic material originating from plants, animals and micro-organisms, including products, by-products, residues and waste from agriculture, forestry and related industries… The entry of impregnated sawdust should be eliminated from Table C-2 simply because it is another form of biomass as listed in Table C-1.

Response: EPA recognizes that Impregnated Saw Dust falls under residual biomass, and has changed the rule language and tables in §98.38 to reflect this.

Commenter Name: Angela Burckhalter
Commenter Affiliation: Oklahoma Independent Petroleum Association (OIPA)
Document Control Number: EPA-HQ-OAR-2008-0508-0386.1
Comment Excerpt Number: 25

Comment: Under Tier 1, EPA proposes that fuel consumption would be based on company records. If no fuel flow meters are installed, we assume this would include a company's best estimate.

Response: EPA acknowledges the commenter's concerns, and has defined the term "company records" in §98.6 of the final rule. EPA believes that the revised definition provides appropriate guidance as to what records a facility may use to determine fuel consumption.

Commenter Name: Jerry Call
Commenter Affiliation: American Foundry Society (AFS)
Document Control Number: EPA-HQ-OAR-2008-0508-0356.2
Comment Excerpt Number: 22

Comment: In section 98.33(c)(4) of the proposed regulation, it appears the paragraph reference should be Table C-3 in lieu of the missing Table C-4.

Response: In the final rule, the proposed language of §98.33(c)(4) has been deleted, and there is no longer a reference to Table C-4.

Commenter Name: See Table 7
Commenter Affiliation:
Document Control Number: EPA-HQ-OAR-2008-0508-0412.1
Comment Excerpt Number: 21

Comment: Overall, GPA supports Subpart C as proposed. In particular, GPA supports the proposed rule's allowance for using "company records" rather than direct fuel measurement for Tier 1 and 2 sources. Midstream sources like GPA members would generally use Tier 1 or 2 calculation methodologies, which allow for calculating CO_2 emissions based on default or measured fuel heating value, default CO_2 emission factors, and fuel quantity from company records.

Response: EPA appreciates your comments and has changed the final rule to allow the use of company records in Tier 1, 2, and 3 calculations. A definition of "company records," as it pertains to quantifying fuel consumption in Tiers 1, 2, and 3, has been added to §98.6.

Commenter Name: Gary Moore
Commenter Affiliation: Pensacola Plant of Ascend Performance Materials LLC
Document Control Number: EPA-HQ-OAR-2008-0508-0366.1
Comment Excerpt Number: 6

Comment: Chemical manufacturing plants may be permitted to burn non-hazardous liquid materials in boilers as fuels. For example, these fuels could be distillation column bottom residues. The residue would not have a default emission factor for CH_4 and N_2O emission calculations. The use of the word "may" in the proposed rule introduces some ambiguity as to the intent of paragraph §98.33(c)(4). The amount of these types of "other" fuels combusted on a national level is likely to be small relative to the amount of listed fuels and the emissions of CH_4 and N_2O are small on a CO_2e basis. Is the reporting the CH_4 and N_2O emissions optional? If emissions are required to be reported, the Agency could propose the use of emission factors from the fuel closest to the "other" fuel being combusted to estimate the CH_4 and N_2O emissions. In this example, the emission factors chosen would be those for Residual Fuel Oil.

Response: EPA acknowledges the commenter's concerns, and has addressed them in the final rule. Section 98.33(c) of the final rule excludes from calculations any CH_4 and N_2O emissions from fuels that are not listed in Table C-2 (formerly C-3). Also, EPA has dropped the provisions that allow facilities burning other fuels to develop site-specific emission factors.

Commenter Name: Paul Dubenetzky
Commenter Affiliation: KERAMIDA Inc.
Document Control Number: EPA-HQ-OAR-2008-0508-0419.1
Comment Excerpt Number: 11

Comment: The U.S. EPA proposes CO_2 emission factors for the combustion of oil generally considered diesel oil in both 40 CFR, Subpart MM, Suppliers of Petroleum Products, Table MM-1, 74 FR 16719 and Table MM-3, 74 FR 16720 and in 40 CFR 98, Subpart C, General Stationary Fuel Combustion, Table C-1. 40 CFR 98, Subpart MM provides specifically for #2 fuel oil and for 100% methyl ester. Methyl ester is motor fuel-grade diesel oil that is derived from plant or animal fat. 40 CFR 98, Subpart C does not provide specific CO_2 emission factors for #2 fuel oil or for 100% methyl ester. Instead, 40 CFR 98, Subpart C provides less specifically for Distillate Fuel Oil (#1, 2, 3, 4) and for Other Oil (> 401 deg. F). The following two points demonstrate the inconsistencies between the CO_2 emission factors for diesel fuel oil found in 40 CFR 98, Subpart MM compared to Subpart C: 1. The 40 CFR 98, Subpart MM, Table MM-1 CO_2 emission factor for # 2 fuel oil is 0.43 metric tons of CO_2 per barrel of oil. Using the default HI-IV of 0.139 mmBtu/gal found in 40 CFR, Subpart C, Table C-1 and the 42 gallons per barrel conversion factor provided in 40 CFR 98 Subpart A, Table A-2 that equates to 430 kilograms per barrel, 10.238 kilograms per gallon, and 73.655 kilograms per mmBtu. The 40 CFR 98, Subpart C, Table C-1 CO_2 emission factor for combusting Distillate Fuel Oil(#1, 2, 3, & 4) is 73.10 kilograms per mmBtu. 2. The 40 CFR 98, Subpart MM, Table MM-3 CO_2 emission factor for 100% methyl ester is 0.40 metric tons of CO_2 per barrel of oil. Using the default factors found in 40 CFR, Subpart C, Table C-1 for Other Oil (> 401 deg. F) and the conversion factors provided by 40 CFR 98 Subpart A, Table A-2 that equates to 400 kilograms per barrel, 9.5238 kilograms per gallon, and 68.52 kilograms per mmBtu. The 40 CFR 98, Subpart C, Table C-1 CO_2 emission factor for Other Oil (> 401 deg. F) is 73.10 kilograms per mmBtu. The U.S. EPA should reconcile these discrepancies while addressing our previously stated comments regarding the significant figures used in calculating GHG emissions and the significant figures used when reporting GHG emissions.

Response: EPA acknowledges the concerns of the commenter, and created better consistency between the default values provided in Table C-1 and the information presented in Subpart MM.

Commenter Name: Lloyd Stone
Commenter Affiliation: Westlake Chemical Corporation
Document Control Number: EPA-HQ-OAR-2008-0508-0442.1
Comment Excerpt Number: 11

Comment: 98.33(b)(5)(ii): This requirement is not consistent with "Table C-1" in the Preamble 98.33(b)(5)(ii) appears to require all units operating for 1000 hours or more annually since 2005 to use Tier 4.

Response: EPA acknowledges the concerns regarding Tier 4 applicability. EPA has revised the rule to clarify that all six criteria must be met before Tier 4 is required.

Commenter Name: Gary Moore
Commenter Affiliation: Pensacola Plant of Ascend Performance Materials LLC
Document Control Number: EPA-HQ-OAR-2008-0508-0366.1
Comment Excerpt Number: 10

Comment: Fence line natural gas GC analyses performed and supplied to customers by the pipeline company should be allowed to meet the sampling and analysis HHV, carbon and molecular weight analysis requirements of the rule. Ascend Performance Materials believes that values supplied by the vendor should be acceptable rather than requiring duplicative testing and the associated costs. This additional testing provides no additional value or accuracy to the calculations.

Response: The final rule clarifies that fuel sampling and analysis data provided by the supplier may be used in the emission calculations, and that fuel billing meters may be used to quantify fuel consumption. To simplify the emission calculations in Tiers 2 and 3, averaging of HHV and carbon content data is permitted if these data are obtained at least at the minimum frequency specified in §98.34. If the results of fuel sampling are received monthly or more frequently, the weighted annual average high heat value shall be calculated using Equation C-2b. If the results of fuel sampling are received less frequently than monthly, then the annual average HHV shall be calculated using the arithmetic average HHV for all valid samples for the year. However, regardless of the sampling frequency, the owner or operator must use the results of all available valid fuel analyses in the emissions calculations.

Commenter Name: Lloyd Stone
Commenter Affiliation: Westlake Chemical Corporation
Document Control Number: EPA-HQ-OAR-2008-0508-0442.1
Comment Excerpt Number: 10

Comment: Should there be the word "and" between §98.33(b)(1)(i) and (ii)?

Response: EPA has considerably revised §98.33(b). The commenter's concern relates to sections that have been substantially edited and/or deleted, and is thus no longer relevant.

Commenter Name: See Table 2
Commenter Affiliation:
Document Control Number: EPA-HQ-OAR-2008-0508-0509.1
Comment Excerpt Number: 10

Comment: A good example is in the Tier 1 – 4 methodologies for calculating CO_2 emissions from fuel combustion. To begin with, EPA creates confusion by failing to include conjunctions when listing a series of items. For example, proposed 40 C.F.R. §98.33(b)(5)(ii) requires the use of the Tier 4 calculation methodology if (A) - (F). But must only one of the (A) - (F) criteria be met, or all of them? (Presumably the latter, but EPA needs to make it clear.) Additional ambiguity is created by EPA's failure to state directly what stack monitoring devices would be required to be installed and maintained by different types of sources. Thus, one could infer from the description of the Tier 4 CO_2 emission calculation methodology in proposed 40 C.F.R. §98.33(a)(4), for example, when read together with the applicability provisions of section 98.33(b)(5) and (6), that a source with a heat input above 250 MMBtu/hr. that burns (at least some??) solid fuel and already is required to have a stack gas monitor or flow monitor (and to meet certain quality assurance testing for that monitor) must install equipment to continuously monitor CO_2 stack gas concentration by no later than January 1, 2011. But that certainly is not clearly stated, and one could also read the proposed regulations to suggest that facilities without a CO_2 monitor (or without an O_2 monitor if their only stack emissions are from fuel combustion) are supposed to use the Tier 3 calculation methodology.

Response: EPA acknowledges the commenter's concerns regarding Tier 4 applicability. EPA has revised the rule to clarify that all six criteria must be met before Tier 4 is required. However, EPA disagrees with suggestions that Tier 4 should only be required if the installed CEMS include a CO_2 monitor. The Tier 4 CEMS requirement is limited to larger solid fossil fuel units with an existing pollutant CEMS and a certified gas monitor of any kind or a stack gas volumetric flow rate monitor. EPA is requiring the use of CEMS due to the complexity of monitoring solid fuel consumption and the heterogeneous nature of the solid fuels. Many of these fossil-fuel fired units with a pollutant CEMS have an existing diluent monitor (O_2 or CO_2) that can be used to determine CO_2 emissions. EPA's estimates of monitoring costs are averages for a representative facility and may not represent the actual cost in individual circumstances.

Commenter Name: Lloyd Stone
Commenter Affiliation: Westlake Chemical Corporation
Document Control Number: EPA-HQ-OAR-2008-0508-0442.1
Comment Excerpt Number: 9

Comment: 98.33(a)(3)(ii): How is liquid fuel that is used as a secondary fuel considered, when not burned in any given month? Is the monthly analysis of carbon content still required? 98.33(a)(3)(iii): Is the monthly analysis of carbon content and molecular weight still required for a gaseous fuel that is used as a secondary fuel considered, when not burned in any given month?

Response: EPA has changed §98.34 to clarify and simplify fuel sampling requirements, revising the sampling frequency requirements. In the final rule, natural gas must be sampled semiannually, while fuel oil and coal must be sampled with each fuel lot. Other liquid fuels and biogas must be sampled once per calendar quarter, and other solid fuels besides municipal solid waste must be sampled weekly to form a composite sample which is analyzed monthly. Where different types of fuel are blended prior to combustion, EPA has added an option to either use a weighted HHV value in the emission calculations based on the relative proportions of each fuel in the blend, or take a representative sample of the blended fuel and analyze it for HHV. EPA believes that these revised requirements provide an appropriate balance between reducing the burden on reporters and obtaining accurate data.

Commenter Name: Kerry Kelly
Commenter Affiliation: Waste Management (WM)
Document Control Number: EPA-HQ-OAR-2008-0508-0376.1
Comment Excerpt Number: 8

Comment: Section 98.33(b)(5)(ii) outlines the conditions under which a reporter must use the Tier4 calculation methodology to estimate a unit's emissions. As drafted, it lists a series of conditions, (A) through (F) with no conjunctions between conditions. We assume the Agency intends that all conditions must be met for the Tier 4 method to apply. Otherwise, the application of just one condition (C) – The unit has operated for more than 1,000 hours in any calendar year since 2005, would require the vast majority of stationary combustion units to use Tier 4. We do not believe the EPA intended such a ludicrous result. We urge the EPA to insert the word "and" between each of the conditions to clarify that all conditions must be met before a unit is subject to Tier 4. Further, per our comments above concerning application of Tier 4 to municipal solid waste combustion, we urge the Agency to delete the second half of condition (A) referring to units that combust MSW and have a maximum rated input capacity greater than 250 tons per day of MSW.

Response: EPA acknowledges the commenters' concerns regarding Tier 4 applicability. EPA has revised the rule to clarify that all six criteria specified in §98.33 must be met before Tier 4 is required. EPA appreciates your comment and has increased the 250 ton MSW/day threshold to 500 ton MSW/day.

Commenter Name: Kerry Kelly
Commenter Affiliation: Waste Management (WM)
Document Control Number: EPA-HQ-OAR-2008-0508-0376.1
Comment Excerpt Number: 39

Comment: In Tier 2 Equation C-2b. The "B" ratio is incorrect and should be revised consistent with the Western Climate Initiative calculation on which it was based. Revised ratio should be: Ratio of boilers maximum design rated heat input capacity to its design rated steam output capacity (mmBtu/lb steam). Same comment for equation C-10b for N_2O and CH_4 calculations.

Response: EPA appreciates the comment but believes that the ratio is satisfactory as written in Equation C-2c. The Agency directs the commenter to the definition of "maximum rated heat input capacity" in §98.6 for further clarification on this matter.

Commenter Name: Traylor Champion
Commenter Affiliation: Georgia-Pacific, LLC (GP)
Document Control Number: EPA-HQ-OAR-2008-0508-0380.1
Comment Excerpt Number: 23

Comment: GP (and, we assume other companies with facilities that use a significant amount of fuel of any type) tracks the amount of fuel purchased very closely since it is, in most cases, a significant part of the overall energy cost. Standard accounting practices require accurate accounting for all fuel purchases and usage. In view of this fact, EPA has chosen the correct option of allowing facilities to use these records to calculate GHG emissions rather than requiring the installation and calibration of new flow meters or weighing system for solid fuels. EPA has proposed requiring facilities that report under the Tier 3 methodology for gas and liquid fuels to install and calibrate flow measurement devices [§98.33(a)(3) FR 16632]. Notwithstanding our preferred approach of using the Tier 1 methodology on fuels coming across the fenceline, as explained above, given that maintaining accurate and complete company records for these fuels is such a high priority for accurate cost accounting, EPA should allow company records to be used for Tier 3 reporting rather than installation and calibration of independent flow devices. Unit level data provides no additional value in terms of facility emissions.

Response: EPA appreciates your comments and has changed the final rule to allow the use of company records in Tier 1, 2, and 3 calculations. A definition of "company records," as it pertains to quantifying fuel consumption in Tiers 1, 2, and 3, has been added to §98.6.

Commenter Name: Ron Downey
Commenter Affiliation: LWB Refractories
Document Control Number: EPA-HQ-OAR-2008-0508-0719.1
Comment Excerpt Number: 22

Comment: The method to calculate hourly emissions proposed in 40 C.F.R. 98.33(a)(4)(v) and 40 C.F.R. 98.33(e)(2)(i), Equation C-12, appears to be inconsistent with Part 75, and may understate emissions during partial hours of operation. The rule requires sources to calculate the mass and volume of CO_2 emitted each hour by multiplying the CO_2 emission rates and hourly flow rates by the fraction of the hour that the source was in operation. Because the downtime is already be accounted for in the hourly average emission rate, there is no need to multiply the hourly average by operating time for that hour. EPA should revise provision to delete the requirement to multiply CO_2 emission rates and hourly flow rates by the fraction of the hour that the source was in operation. LWB proposes that total combustion emissions be calculated by summing the hourly averages during operation times throughout the year to be consistent with Parts 60 and 75.

Response: EPA appreciates your support and thanks you for your comment. The discrepancy has been reconciled in the final rule.

Commenter Name: Lorraine Krupa Gershman
Commenter Affiliation: American Chemistry Council (ACC)
Document Control Number: EPA-HQ-OAR-2008-0508-0423.2
Comment Excerpt Number: 51

Comment: In §98.33(a)(4)(i), EPA refers in this section to paragraph (a)(1)(iv)(D) of this section; however, this reference does not appear to exist in the proposed rule and EPA needs to correct this reference.

Response: EPA has corrected this error. The paragraph referenced in the comment (§98.33(a)(4)(i) in the final rule) now refers to section §98.33(a)(4)(iv).

Commenter Name: Thomas Diamond
Commenter Affiliation: Semiconductor Industry Association (SIA)
Document Control Number: EPA-HQ-OAR-2008-0508-0498.1
Comment Excerpt Number: 35

Comment: SIA provided a redline version of proposed rule that reflects SIA's proposed alternatives. [See DCN: EPA-HQ-OAR-2008-0508-0498.1]

Response: In regard to electronics manufacturing, Subpart I, EPA is not going final with that source category at this time. Please see Section III. I. of the Preamble and the separate comment response document.

Commenter Name: Lauren E. Freeman
Commenter Affiliation: Hunton & Williams LLP
Document Control Number: EPA-HQ-OAR-2008-0508-0493.1
Comment Excerpt Number: 35

Comment: With respect to the proposed emission factors, UARG notes that the value for CH_4 in Table C-3 is significantly higher than the equivalent units under AP-42 (roughly 35 ppm versus 2.7 ppm). In addition, although the N_2O values in Table C-3 are closer to the AP-42 values for that gas, AP-42 also differs from Table C-3 in that it provides different values for wall-fired boilers than for tangentially-fired boilers. A "Note" at the bottom of Table C-3 states that, "for coal combustion," units that fall within the IPCC "Energy Industry" category may "employ a value of 1 g of CH_4/MMBtu." That value is much closer to the AP-42 value for CH_4. UARG does not understand why this alternative CH_4 value for coal combustion is hidden in a note at the bottom of the table. Nor is it clear in the rule where one would look to determine whether a unit is within the cited IPCC category. [Footnote: UARG assumes EPA is referring to the 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 2, but that is far from clear.] UARG requests that EPA clarify in the table (rather than merely in a note) which units may use the alternative CH_4 value in Table C-3, and that the Agency allow sources to use the more specific AP-42 values for N_2O where they are applicable.

Response: EPA listed fuel types and respective default emission factors for CH_4 and N_2O in Subpart C are sufficient for reporting. For the purposes of the rule, which is data collection for policy development, we would prefer consistent use of default CH_4 and N_2O emission factors. In this case, we provide the values we would like reporters to use, and for verification purposes, would prefer consistent use of these factors. Based on comments, additional factors have been added to Table C-2 (formerly C-3), and other factors may be brought into future programs, but for this rulemaking, given the very small comparative amounts of CH_4 and N_2O emitted relative to CO_2, we have chosen to use the listed default factors. EPA is using mostly IPCC values because the AP-42 non-CO_2 factors have not been reviewed in depth recently.

Commenter Name: Ron Downey
Commenter Affiliation: LWB Refractories
Document Control Number: EPA-HQ-OAR-2008-0508-0719.1
Comment Excerpt Number: 32

Comment: 40 C.F.R. 98.33(b) indicates that units combusting multiple fuel types (e.g., burning coal and natural gas in the same kiln) could be required to use two different emission calculation methodologies (tiers) in order to calculate stationary fuel combustion. We request confirmation that it is permissible to use multiple tiers for each fuel type combusted by a single unit. 40 C.F.R. 98.33(b)(5)(ii)(A) - (F) sets forth conditions for use of the Tier 4 methodology. LWB interprets this provision to require that sources meet all six conditions in order for Tier 4 to apply. LWB proposes that each condition in 40 C.F.R. 98.33(b)(5)(ii)(A) - (F) end with a semi-colon and that after the semi-colon in 40 C.F.R. 98.33(b)(5)(ii)(E), the word "and" be added to clearly indicate that all six conditions must be met before requiring use of the Tier 4 emission calculation methodology.

Response: EPA acknowledges the commenters' concerns regarding Tier 4 applicability. EPA has revised the rule to clarify that all six criteria must be met before Tier 4 is required. If Tier 4 is required then all the CO_2 emissions are quantified from all fuel types using Tier 4. §98.33(a)(6).

Commenter Name: Ron Downey
Commenter Affiliation: LWB Refractories
Document Control Number: EPA-HQ-OAR-2008-0508-0719.1
Comment Excerpt Number: 31

Comment: 40 CFR Part 98.33(a)(4)(iv) permits the use of an O_2 monitor to meet the CEMS monitoring requirement for Tier 4. However, 40 C.F.R. Part 75 permits O_2 measurements to serve as a surrogate for CO_2 if the effluent gas stream monitored by the CEMS consists solely of combustion products and if only fuels listed in Table 1 are combusted. As written, the Proposed Rule does not clearly indicate whether a facility with an O_2 monitor would be required to use a CEMS. In the case of lime, an O_2 monitor could not be used to determine their CO_2 emissions due to the presence of process related emissions. The Proposed Rule does not impose any limits on the use of O_2 data as a surrogate for CO_2. See 40 CFR Part 98.33(a)(4)(iv). Part 60 and 75 allow O_2 measurements to serve as a surrogate for CO_2 because Part 75 only addresses CO_2

from fuel combustion. Similarly, the Western Climate Initiative's reporting rule allows the use of O_2 measurements as a surrogate for CO_2 in limited situations. LWB would like to know the basis for EPA's conclusion that O_2 measurements are always an appropriate surrogate for determining CO_2 emissions from a lime kiln. 40 CFR Part 98.33(a)(4)(iv) should be clarified to state that sources not allowed to use O_2 data as a surrogate for CO_2 would not be subject to Tier 4 solely on the basis of having an O_2 monitor. In addition, this provision should be made consistent with the Western Climate Initiative's Final Draft of Essential Requirements of Mandatory Reporting and Part 75, by identifying the limited situations in which O_2 measurements can be used as a surrogate for CO_2.

Response: EPA has revised the final rule to provide clarity concerning gas monitors and Tier 4 requirements. Tier 4 shall be used only if the unit meets six conditions, one of which is "the installed CEMS include a gas monitor of any kind or a stack gas volumetric flow rate monitor, or both . . ." Further, EPA allows an oxygen (O_2) concentration monitor to be used in lieu of a CO_2 concentration monitor to determine the hourly CO_2 concentrations in accordance with Equation F-14a or F-14b (as applicable) in Appendix F to Part 75, if the effluent gas stream monitored by the CEMS consists solely of combustion products (i.e., no process CO_2 emissions are mixed with the combustion products).

Commenter Name: Lauren E. Freeman
Commenter Affiliation: Hunton & Williams LLP
Document Control Number: EPA-HQ-OAR-2008-0508-0493.1
Comment Excerpt Number: 30

Comment: UARG notes that some confusion has been caused by EPA's failure to specify in the proposed rule whether all, or only one, of the criteria in proposed §98.33(a)(4)(A) - (F) triggers Tier 4. To avoid confusion, UARG suggests that EPA add an "and" at the end of subsection (E).

Response: EPA acknowledges the commenters' concerns regarding Tier 4 applicability. EPA has revised the rule to clarify that all six criteria must be met before Tier 4 is required.

Commenter Name: Lauren E. Freeman
Commenter Affiliation: Hunton & Williams LLP
Document Control Number: EPA-HQ-OAR-2008-0508-0493.1
Comment Excerpt Number: 29

Comment: Tier 2, also applicable to units with a maximum rated heat input capacity of 250 mmBtu/hr or less, uses fuel-specific default CO_2 emission factors, a measured HHV, and monthly fuel consumption from company records to calculate annual CO_2. Tier 2 can be used as long as the applicable CO_2 default value is provided in either Table C-1 or C-2 (alternative fuels). Proposed §§98.33(a)(2) and (b)(3). According to the Preamble, and Equation C-2a, fuel is measured monthly. 74 Fed.Reg. at 16,484, 16,632. Proposed §98.34(c)(2), however, specifies weekly sampling to develop a composite for monthly analysis of coal, and other solid fuels. EPA should clarify its description and equation to reflect the more specific provisions in §98.34(c). Tier 3, applicable to any unit for which Tier 4 is not elected or required, uses measured fuel carbon, molecular weight (for gases), and the quantity of fuel combusted. Proposed §§98.33(a)(3) and (b)(4). For liquid and gaseous fuel, the volume is measured with fuel flow meters (including gas billing meters) or, for oil, tank drop measurements. Coal consumption is measured with company records. Proposed §§98.33(a)(3). Carbon content is measured monthly for natural gas, biogas, and liquid fuels, monthly for coal and other solid fuel (based on a weekly composite), and daily for other gaseous fuel (e.g., refinery gas or process gas). Proposed §98.34(d)(3). EPA assumes that daily measurements would be made with in-line gas chromatographs that are already in place for process purposes. 74 Fed. Reg. 16484. All oil and gas flow meters (except for gas billing meters) must be calibrated prior to the first reporting year using either a test method listed in §98.7 or "the calibration procedures specified by the flow meter manufacturer," and must be recalibrated either annually or "at the minimum frequency specified by the manufacturer." Proposed §98.34(d)(1). For both Tier 2 and Tier 3 methodologies, only those sampling and analysis methods incorporated under proposed §98.7 can be used. Proposed §98.34(c) and (d). To ensure that this list is complete and that the methods provided are up to date, UARG requests that EPA also allow use of any applicable method that is listed under 40 C.F.R. §75.6.

Response: The final rule clarifies that fuel sampling and analysis data provided by the supplier may be used in the emission calculations, and that fuel billing meters may be used to quantify fuel consumption. To simplify the emission calculations in Tiers 2 and 3, averaging of HHV and carbon content data is permitted if these data are obtained at least at the minimum frequency specified in §98.34. If the results of fuel sampling are received monthly or more frequently, the weighted annual average high heat value shall be calculated using Equation C-2b. If the results of fuel sampling are received less frequently than monthly, then the annual average HHV shall be calculated using the arithmetic average HHV for all valid samples for the year. However, regardless of the sampling frequency, the owner or operator must use the results of all available valid fuel analyses in the emissions calculations.

EPA has incorporated by reference all methods deemed appropriate into Part 98, and therefore does not believe it is necessary to allow the use of methods listed under 40 C.F.R §75.6.

Commenter Name: See Table 5
Commenter Affiliation:
Document Control Number: EPA-HQ-OAR-2008-0508-0480.1
Comment Excerpt Number: 40

Comment: Table C-3 of the Proposed Rule includes default CH_4 and N_2O emission factors for natural gas and §98.33(c) indicates that default values in Table C-3 should be used to calculate emissions. As an alternative, operator-defined emission factors should be accepted if the basis for the factors is documented and technically defensible (e.g., reference methods or reasonable standards for measurement; engine vendor provided test data). Typically, estimates based on source-specific emission factors would be more appropriate than an estimate based on a generic emission factor and the operator should have the opportunity to justify use of operator defined emission factors for methane or N_2O. In some cases, operators may already be estimating GHG emissions using more appropriate source-specific emission factor methods and should not have to default to generic emission factors that may not be accurate for a particular source type.

Response: EPA believes the listed fuel types and respective default emission factors for CH_4 and N_2O listed in Subpart C are sufficient for reporting. For the purposes of the rule, which is data collection for policy development, we would prefer consistent use of default CH_4 and N_2O emission factors. For this rulemaking, given the very small comparative amounts of CH_4 and N_2O emitted relative to CO_2, we have chosen to use the listed default factors. Also, additional factors have been added to Table C-2 (formerly C-3), and other factors may be brought into future programs.

Commenter Name: Ron Downey
Commenter Affiliation: LWB Refractories
Document Control Number: EPA-HQ-OAR-2008-0508-0719.1
Comment Excerpt Number: 23

Comment: 40 C.F.R. 98.33(e)(2)(i), Equation C-12 refers to measuring the "hourly CO_2 concentration" and the "hourly stack gas volumetric flow rate." This Equation should be revised to replace "hourly CO_2 concentration" with "hourly average CO_2 concentration" and "hourly stack gas volumetric flow rate" with "hourly average stack gas volumetric flow rate" because the source will determine the hourly average CO_2 concentration and flow rate based on multiple samples that must be collected in accordance with Part 60 and 75 requirements.

Response: EPA thanks you for your comment. The discrepancy has been reconciled in the final rule.

Commenter Name: Fiji George
Commenter Affiliation: El Paso Corporation
Document Control Number: EPA-HQ-OAR-2008-0508-0398.1
Comment Excerpt Number: 41

Comment: The term "measurement of HHV" or similar phrases are used in §98.33 with respect to Tier 2 calculation of CO_2 emissions from combustion sources. In addition method ASTM D1826-94 Standard Test Method for Calorific (Heating) Value of Gases in Natural Gas Range by Continuous Recording Calorimeter, is incorporated by reference in §98.7. This could be interpreted to mean that measured HHV for natural gas must be obtained using the referenced ASTM method. In fact, our FERC Gas Tariff requires that we determine the HHV of the gas using an in-line gas chromatograph or a chromatograph analysis of a sample or composite sample. The constituents of the analyzed gas are separated into columns, and a mole percentage of each component is determined. Each component's specific heating value is multiplied by mole percentage and subsequently is summed into the HHV value. Therefore, the HHV value that we will provide to our customers or which is specific to the gas that fuels our own combustion sources is 'a calculated off of a gas composition' and is not considered 'measured' value. El Paso recommends that the term "measured HHV" be replaced by "measured or calculated HHV" when referring to Tier 2 emissions from combustion of pipeline quality natural gas and that the standards be expanded to include the following industry standards: 1. Spot or Composite Sample: Related Industry Standard API 14.1 & GPA 2166. 2. Online Chromatograph: Related Industry Standard API 14.1. 3. Lab Chromatograph: Related Industry

Standard GPA 2198, GPA 2286. 4. Heating Value Calculation: Related Industry Standard API 14.1, GPA 2145, GPA 2172, AGA 5, AGA 8.

Response: In the final rule, the HHV may be calculated using chromatographic analysis together with standard heating values of the fuel constituents. EPA has added language in §98.33 clarifying that either the owner or operator or the fuel supplier may be responsible for the sampling and analysis for HHV. Section 98.34 further clarifies that the fuel sampling may be performed by the owner or operator, the fuel supplier, or an independent laboratory. EPA has also added flexibility to the use of the four Tiers, and has reduced the frequency of required sampling for many fuels, including natural gas. To simplify the emission calculations in Tiers 2 and 3, averaging of HHV and carbon content data is permitted if these data are obtained at least at the minimum frequency specified in §98.34. If the results of fuel sampling are received monthly or more frequently, the weighted annual average high heat value shall be calculated using Equation C-2b. If the results of fuel sampling are received less frequently than monthly, then the annual average HHV shall be calculated using the arithmetic average HHV for all valid samples for the year. EPA has included similar equations for units combusting solid and liquid fuels using Tier 3. However, for gaseous fuels using Tier 3, EPA has decided to require facilities to use average carbon content determinations and fuel consumption for each measurement period (as specified in §98.34(b)(3)). EPA has added language to §98.33(c)(2) clarifying that Equation C-9a uses total fuel consumption during the reporting year and annual average HHV determinations.

Commenter Name: Robert Rouse
Commenter Affiliation: The Dow Chemical Company
Document Control Number: EPA-HQ-OAR-2008-0508-0533.1
Comment Excerpt Number: 21

Comment: Comments on the Tier 1 – 4 Methods are Provided Below: In 98.33(a)(3)(iii), the proposed Tier 3 methodology for a gaseous fuel requires the use of Equation C-5, which contains the term MVC. MVC is defined as the molar volume conversion factor and is stated to be equal to 849.5 scf per kg-mole at standard conditions for this equation and also throughout the rule. However, in 98.6, Definitions, EPA defines the term "Standard Conditions or Standard Temperature and Pressure" as meaning 60 degrees F and 14.7 psia. Using a temperature of 60° F, molar volume is calculated to be (10.73)(520)/(14.7) = 379.6 scf/lb-mole x 2.2 = 835 scf/kg-mole. Thus, there appears to be a discrepancy between the standard conditions in the definitions and the standard conditions for the conversion factor in Equation C-5. It appears EPA may have used a temperature of 68 °F to obtain a molar volume of 849.5 scf/kg-mole. Thus, the molar volume that is required to be used doesn't match with a standard temperature of 60° F. EPA could either revise the molar volume to closer to 835 scf/kgmole or revise the definition of Standard Conditions to reflect a temperature of 68° F. Section 98.33(a)(4)(i) – EPA refers in this section to paragraph (a)(1)(iv)(D) of this section. However, this reference does not appear to exist in the proposed rule and EPA needs to correct this reference.

Response: EPA has corrected this error. The paragraph referenced in the comment (§98.33(a)(4)(i) in the final rule) now refers to §98.33(a)(4)(iv).

EPA has revised the definition of "Standard conditions or standard temperature and pressure (STP)" in §98.6 to mean "68 degrees Fahrenheit and 14.7 pounds per square inch absolute." Given this revised definition, EPA believes that the value for MVC provided in Equation C-5 is correct.

Commenter Name: Ron Downey
Commenter Affiliation: LWB Refractories
Document Control Number: EPA-HQ-OAR-2008-0508-0719.1
Comment Excerpt Number: 20

Comment: The requirement in 40 C.F.R. 98.33(b)(6)(ii) to install and certify CEMS by January 1, 2011 may not be achievable given the need to select, deliver, engineer, and install and certify the equipment. Installation of CEMS may be delayed due to the potential for increased demand for equipment and stack testing consultants. EPA should revise 40 C.F.R. 98.33(b)(6)(ii) to require installation and certification of CEMS by January 1, 2012.

Response: The final rule requires data collection for calendar year 2010, but has been changed since proposal to allow use of best available monitoring methods for the first part of 2010. EPA acknowledges the concerns of the commenters, and has clarified the rule for those units that must upgrade their existing CEMS to meet Tier 4 requirements. If all the monitors needed have not been installed and certified by January 1, 2010, they may use either Tier 2 or 3 in 2010.

Commenter Name: Kyle Pitsor
Commenter Affiliation: National Electrical Manufacturers Association (NEMA)
Document Control Number: EPA-HQ-OAR-2008-0508-0621.1
Comment Excerpt Number: 20

Comment: The NEMA Carbon/Manufactured Graphite EHS Committee's understanding from §98.33(b)(4) is that the Tier 3 calculation method "may be used" (i.e., at the facility's discretion) for a unit of any size and for any type of fuel, except when Tier 4 is required by the rule. However, this is confused by the apparent indication in Table C-1 and discussions in the Preamble that Tier 3 is "required" for gaseous and liquid fossil fuel use when the combustion unit size exceeds 250 mmBtu/hr. The NEMA Carbon/Manufactured Graphite EHS Committee wanted to bring this apparent discrepancy to EPA's attention, and for the reasons explained below, express our opinion that use of the Tier 1 and Tier 2 methods should be allowed by EPA for estimating GHGs from combustion of gaseous and liquid fossil fuels available from commercial sources, regardless of the size of the combustion unit(s). We are not familiar with gaseous and liquid fuels that may be obtained from private wells, so are not offering an opinion as to whether emissions from those fuel sources warrant use of the more complex Tier 3 calculation method.

Response: In response to comments, EPA has substantially revised §98.33(b), describing which tier a reporter is to use. EPA has also expanded the use of the Tier 2 Calculation Methodology for CO_2 emissions to include units greater than 250 mmBtu/hr that combust only pipeline natural gas and/or distillate oil.

Commenter Name: Ronald H. Strube
Commenter Affiliation: Veolia ES Solid Waste
Document Control Number: EPA-HQ-OAR-2008-0508-0690.1
Comment Excerpt Number: 19

Comment: We request clarification of §98.33(b)(5)(ii). We believe that EPA's intent is to require the use of the Tier 4 calculation only if a unit meets the requirements of all 6 subheadings, otherwise the Tier 4 calculation is not required. We are concerned that if it is required for a single subheading, for instance (C): the unit has operated for more than 1,000 hours in any calendar year since 2005, this will include every landfill gas to energy project in the U.S. Furthermore, this requires the installation of continuous monitoring equipment on the stacks of each emission unit, a requirement that currently exceeds the vast majority of operating air permits. The requirement to install this equipment by 2011 is unduly burdensome.

Response: See the Preamble section, "GHG Emissions Calculation and Monitoring, Calculating CO_2 Emissions from Combustion" for a discussion of Tier 4.

EPA acknowledges the commenter's concerns regarding Tier 4 applicability. EPA has revised the rule to clarify that all six criteria must be met before Tier 4 is required. The final rule requires data collection for calendar year 2010, but has been changed since proposal to allow use of best available monitoring methods for the first part of 2010.

Commenter Name: See Table 3
Commenter Affiliation:
Document Control Number: EPA-HQ-OAR-2008-0508-0433.2
Comment Excerpt Number: 19

Comment: NPRA finds that the CEMs requirements proposed by EPA as Tier 4 monitoring in 40 CFR 98 Subpart C (proposed) for combustion sources burning solid fuels and municipal solid waste (MSW) appear technically sound with respect to many such combustion sources, within the limits of CEMs accuracy. However, unlike the Preamble, the proposed rule text in §98.33(b)(5)(ii) is not clear in specifying that Tier 4 is required only for solid fuel-fired or MSW-fired combustion sources. The rule text should be clarified to state that Tier 4 (CEMs) monitoring is mandatory only if all of the conditions in §98.33(b)(5)(ii) (A) through (F) are met. This would provide consistency between the Preamble and the final regulation and ensure that facilities and enforcement personnel are clear on when a Tier 4 monitoring approach is required.

Response: EPA acknowledges the commenter's concerns regarding Tier 4 applicability. EPA has revised the rule to clarify that all six criteria specified in subparagraphs (A) through (F) must be met before Tier 4 is required.

Commenter Name: Ron Downey
Commenter Affiliation: LWB Refractories
Document Control Number: EPA-HQ-OAR-2008-0508-0719.1
Comment Excerpt Number: 19

Comment: The proposed definition of "continuous emissions monitoring system" (CEMS) in 40 C.F.R. 98.6 includes those systems that have a gas extraction system or only a flow monitor. The definition of CEMS is significant because facilities with CEMS are required to use the Tier 4 calculation methodology. The Proposed Rule's definition of CEMS is overbroad in that it could be interpreted to include those facilities that only have a flow monitor or an in-situ monitor. Sources with in-situ monitors could be required to send the monitor back to the manufacturer for equipment upgrades and calibrations to upgrade to a monitor so that it is capable of measuring CO_2 emissions, which could take months based on previous experience. This would result in the facility being out of compliance with other Clean Air Act monitoring requirements (e.g., Title V). Sources with only a flow monitor could be required to install full monitoring systems in order to measure CO_2. This definition of CEMS should be revised to differentiate between monitors that can readily be upgraded to measure CO_2 and those that cannot. LWB proposes that the definition of CEMS in 40 C.F.R. 98.6 be revised as follows: "Continuous emission monitoring system or CEMS means the total equipment required to sample, analyze, measure, and provide, by means of reading recorded at least once every 15 minutes, a permanent record of gas concentrations, and pollutant emissions rates from stationary sources that have a gas extraction system." LWB's proposed definition is consistent with EPA's intent to require sources to make use of existing equipment and not impose substantial operational burdens by the need to add an entire gas extraction system.

Response: EPA disagrees with the commenter's suggestion, and intends for Tier 4 to apply to sources where installed CEMS include a gas monitor of any kind, or a stack gas volumetric flow monitor, or both, provided that the source meets all of the other conditions specified in the rule. The Tier 4 CEMS requirement is limited to larger solid fossil fuel units with an existing pollutant CEMS and which include a certified gas monitor of any kind or a stack gas volumetric flow rate monitor. EPA is requiring the use of CEMS due to the complexity of monitoring solid fuel consumption and the heterogeneous nature of the solid fuels. Many of these fossil-fuel fired units with a pollutant CEMS have an existing diluent monitor (O_2 or CO_2) that can be used to determine CO_2 emissions.

Commenter Name: Kyle Pitsor
Commenter Affiliation: National Electrical Manufacturers Association (NEMA)
Document Control Number: EPA-HQ-OAR-2008-0508-0621.1
Comment Excerpt Number: 19

Comment: The citation on page 16634 under §98.33(b)(5)(ii)(c) appears to require any combustion unit that has operated for more than 1,000 hours in any calendar year since 2005 to use the Tier 4 Calculation Method, and therefore would require the installation and operation of CEMS even if this monitoring equipment is not currently installed. (Since there is no "and" provided in the list of criteria, the NEMA Carbon/Manufactured Graphite EHS Committee has therefore interpreted the requirement to apply to any one listed criterion "or" another.) Firstly, each facility may be unable to establish the annual hours of operation of each stationary fuel combustion unit since 2005, as it was not a past legal requirement to maintain such documentation of operations. There is no convincing reason or known legal precedent to go back to historical operations records several years before a reporting rule becomes effective. Even if this operational documentation is available at a facility, this language is totally unfounded and unnecessary for the same arguments as above, i.e., sufficiently accurate and consistent fuel usage data can be collected and GHG emissions estimated using standard recognized protocols without this additional burden on the regulated community. The number of hours of operation would have negligible impact on the accuracy or consistency of using any of the other recognized GHG emission estimation methods, using readily available fuel usage data and default emission factors available for all the common fuels. Secondly, according to Table C-1 in the Preamble, this criterion only applies to combustion units burning > 250 mmBtu/hour solid fossil fuels or > 250 tons/day municipal solid waste (MSW). Liquid and gaseous fossil fuels, in particular, natural gas, are amongst the cleanest burning and homogenous fuels available, so that this 1,000 hour per year operation time criteria should not apply to them. On page 11 of EPA's Technical Supporting Document (TSD) for the proposed rule, dated Jan 30, 2009, Section 3.2.1 Tier 4 Methodology also indicates that CEMS are being required for large solid fuel units and MSW units, where there is uncertainty in heating value and carbon content. Default emission factors are available and sufficiently accurate for gaseous and liquid fossil fuels, so Tier 1 or Tier 2 (if monthly high heating value information is available) should be acceptable. The §98.33(b)(5)(ii)(c) language in the Final Rule should be written to be clearer and consistent with Table C-1. This language, unless clarified, could conceivably make a large number of covered facilities unnecessarily install and operate CEMS. In summary, the NEMA Carbon/Manufactured Graphite EHS Committee believes that EPA should not require CEMS at any reporting facilities, regardless of quantities or types of fuels combusted each year, that are not currently required to have them under other existing air permitting or other regulatory programs, as there is insufficient justification for EPA to make the monitoring or recordkeeping requirements for GHGs more onerous than existing programs for regulated priority pollutants or hazardous air pollutants. This is especially true for purchased gaseous and liquid fossil fuels, which are largely homogenous and for which credible alternative emissions estimation protocols based on metered fuel usage already exist. Similarly, a requirement to install CEM on units for which limited or no other regulatory requirements exist due to "grandfather" status under state air permitting programs appears to be unjustified.

Response: EPA acknowledges the commenter's concerns regarding Tier 4 applicability. EPA has revised the rule to clarify that all six criteria specified in must be met before Tier 4 is required.

Commenter Name: Lauren E. Freeman
Commenter Affiliation: Hunton & Williams LLP
Document Control Number: EPA-HQ-OAR-2008-0508-0493.1
Comment Excerpt Number: 27

Comment: UARG also notes that its acceptance of a requirement for ARP units to rely on their Part 75 cumulative CO_2 mass emissions estimates is limited to this rulemaking, and might not extend to rules regulating emissions of CO_2. CO_2 mass emissions data reported under Part 75 are affected by a rule requiring so-called "bias" adjustment of volumetric flow monitor data based on the results of a statistical analysis of relative accuracy test audit ("RATA") data comparing the flow monitor's response to data from an EPA reference method. See, e.g., Part 75, Appendix A, §7.6. If the RATA data are determined to be "biased" based on a one-tailed test, all hourly volumetric flow monitor data from the time of that RATA forward are adjusted "upward" by a calculated bias adjustment factor -- called a "BAF" -- until the next RATA and bias test are conducted. UARG has opposed this requirement from the start of the ARP. In UARG's view, the test, which is based on data from a single stack test, does not represent true "bias." The test also does not allow for adjustment of data downward if the test indicates that the so-called "bias" in the data is positive. Adjustment of volumetric flow monitoring data in this manner can result in a significant difference in the reported, versus the measured, CO_2 mass emissions. When EPA has relied upon Part 75 data in other regulatory programs, like the NSPS, EPA has always made clear that sources are to use the unadjusted data, which is also recorded. See, e.g., 40 C.F.R §§60.48Da(j)(2), (k)(ii), 60.49Da(c)(2) and (d). However, because Part 75 does not require calculation of hourly CO_2 mass emissions in its "unadjusted" form (only unadjusted hourly volumetric flow data are reported), using unadjusted data for the purposes of this rule would require additional calculations and software changes for ARP units. ARP units could not rely on their reported cumulative values. As a result, UARG is not seeking an alternative to report unadjusted data at this time, but may do so in a future rulemaking if the data are to be used for regulatory purposes.

Response: Under this rulemaking, EPA is not revising Part 75 reporting requirements. See the Preamble, Section III. C., the Subpart D comment response document volume, and the response to comment EPA-HQ-OAR-2008-0508-0956.1 excerpt 20 for the rationale for using substitute data reported under Part 75.

Commenter Name: See Table 3
Commenter Affiliation:
Document Control Number: EPA-HQ-OAR-2008-0508-0433.2
Comment Excerpt Number: 58

Comment: In Section 98.33(c)(2)(i) for General Stationary Fuel Combustion Sources, clarify the language to insure that HHV can be determined by the owner/operator. As currently written, it can be interpreted to only allow HHV as being measured or provided by the "entity supplying the fuel". In Table C-1, the CO_2 factors are based on HHV, and the text should state this explicitly. Also, the source of the emission factors is not referenced.

Response: EPA has added language in §98.33 clarifying that either the owner or operator or the fuel supplier may be responsible for the sampling and analysis for HHV. Section 98.34 further clarifies that the fuel sampling may be performed by the owner or operator, the fuel supplier, or an independent laboratory. EPA has also added flexibility to the use of the four tiers, and has reduced the frequency of required sampling for many fuels, including natural gas. To simplify the emission calculations in Tiers 2 and 3, averaging of HHV and carbon content data is permitted if these data are obtained at least at the minimum frequency specified in §98.34. If the results of fuel sampling are received monthly or more frequently, the weighted annual average high heat value shall be calculated using Equation C-2b. If the results of fuel sampling are received less frequently than monthly, then the annual average HHV shall be calculated using the arithmetic average HHV for all valid samples for the year. EPA has included similar equations for units combusting solid and liquid fuels using Tier 3. However, for gaseous fuels using Tier 3, EPA has decided to require facilities to use average carbon content determinations and fuel consumption for each measurement period (as specified in §98.34).

EPA believes that the note below Table C-1 in §98.38 sufficiently states that the CO_2 emission factors are based on HHV. The Agency refers the commenter to Appendix C of the Technical Support Document for Stationary Fuel Combustion Emissions (EPA-HQ-OAR-2008-0508-0004) for the source of the emission factors.

Commenter Name: See Table 6
Commenter Affiliation:
Document Control Number: EPA-HQ-OAR-2008-0508-0679.1
Comment Excerpt Number: 106

Comment: §98.33(d), Equation C-11. This equation appears to be missing a term – a conversion "moles acid gas removed/mole sorbent." The units of the equation as presented do not currently result in metric tons CO_2 emitted.

Response: EPA has corrected this error in the final rule. The R term has been redefined as "1.00, the calcium-to-sulfur stoichiometric ratio."

Commenter Name: See Table 6
Commenter Affiliation:
Document Control Number: EPA-HQ-OAR-2008-0508-0679.1
Comment Excerpt Number: 105

Comment: Pg 16635, §98.33(c)(4) – Section 98.33(c)(4) refers to Table C-4 when referencing CH_4 and N_2O emission factors but there is no Table C-4. The reference should be revised to Table C-3.

Response: In the final rule, the original language in §98.33(c)(4) has been deleted.

Commenter Name: See Table 6
Commenter Affiliation:
Document Control Number: EPA-HQ-OAR-2008-0508-0679.1
Comment Excerpt Number: 104

Comment: §98.33(b)(5)(ii) and (iii) – EPA should revise paragraphs §98.33(b)(5)(ii) and (iii) to emphasize that the Tier 4 calculation methodology must be used for units that combust solid fuels or MSW and that meet the requirements in the subparagraphs. As stated in the Preamble on page 16483 "The most stringent emissions calculation methods would apply to large stationary combustion units that are fired with solid fuels and that have existing CEMS equipment." Thus, if a combustion unit does not burn solid fuel or MSW, it is optional for the owner or operator to use Tier 4 (CEMS) according to §98.33(b)(5)(i). API suggests revising §98.33(b)(5)(ii) and (iii) to read as follows: (5) The Tier 4 Calculation Methodology: (I) May be used for a unit of any size, combusting any type of fuel. (ii) Shall be used for a unit if: (A) The unit has a maximum rated heat input capacity greater than 250 MMBtu/hr, or if the unit combusts municipal solid waste and has a maximum rated input capacity greater than 250 tons per day of MSW, and (B) The unit combusts solid fossil fuel or MSW, either as a primary or secondary fuel, and (C) The unit has operated for more than 1,000 hours in any calendar year since 2005, or (D) The unit meets the criteria in (B) and (C) directly above, and (E) The unit has installed CEMS that are required either by an applicable Federal or State regulation or the unit's operating permit, and (F) The installed CEMS include a gas monitor of any kind, a stack gas volumetric rate monitor, or both and the monitors have been certified in accordance with the requirements of Part 75 of this chapter, Part 60 of this chapter, of an applicable State continuous monitoring program, and (G) The installed gas and/or stack gas volumetric flow rate monitors are required, by an applicable Federal or State regulation of the unit's operating permit, to undergo periodic quality assurance testing in accordance with Appendix B to Part 75 of this chapter, Appendix F to Part 60 of this chapter, or an applicable State continuous monitoring program. (iii) Shall be used for a unit with a maximum rated heat input capacity of 250 MMBtu/hr or less and for a unit that combusts municipal solid waste with a maximum rated input capacity of 250 tons of MS W per day or less, if the unit: (A) Has both a stack gas volumetric flow rate monitor and a CO_2 concentration monitor, and (B) The unit meets the other conditions specified in paragraphs (b)(5)(ii)(B) of this section, and (C) The CO_2 and stack gas volumetric flow rate monitors meet the conditions specified in paragraphs (b)(5)(ii)(D) through (b)(5)(ii)(F) of this section.

Response: EPA acknowledges the commenter's concerns regarding Tier 4 applicability. EPA has revised the rule to clarify that all six criteria must be met before Tier 4 is required.

Commenter Name: See Table 6
Commenter Affiliation:
Document Control Number: EPA-HQ-OAR-2008-0508-0679.1
Comment Excerpt Number: 102

Comment: §98.33(a)(4)(iii), Equation C-7. The units for the variable CO_2 (calculated using Equation C6) should be changed from (tons/hr) to (metric tons/hr). This change is consistent with the stated units for the variable CO_2 as defined in Equation C-6.

Response: EPA has corrected this error in the final rule.

Commenter Name: See Table 6
Commenter Affiliation:
Document Control Number: EPA-HQ-OAR-2008-0508-0679.1
Comment Excerpt Number: 101

Comment: §98.33(a)(4)(ii), Equation C-6. The units for the conversion factor 5.18×10^{-7} should be changed from (tons/scf-% CO_2) to (metric tons/scf-% CO_2). This change is consistent with the conversion of the original constant [5.7 x 10^{-7} (tons/scf-% CO_2), as presented in 40 CFR §75, Appendix F] to metric units for the proposed rule.

Response: EPA has corrected the unit label for the conversion factor. It now reads (metric tons/scf/% CO_2). EPA believes that the value of the conversion factor provided in Equation C-6 is accurate, given these revised units.

Commenter Name: Karen St. John
Commenter Affiliation: BP America Inc. (BP)
Document Control Number: EPA-HQ-OAR-2008-0508-0631.1
Comment Excerpt Number: 65

Comment: EPA lays out a four tiered monitoring system based on fuel type and unit size. There is a conflict between language in the Preamble of the proposed rule and the text shown in Subpart C of the rule. The Preamble states that continuous emission monitoring systems (CEMS) are only required for combustion devices fired by solid fuels, or otherwise required by existing rules or permits. However, the rule language regarding selection of the "Tier" level (Section 98.33(b)(5)), as currently written, would require CEMS for any combustion unit that has a maximum rated heat input greater than 250,000 Btu/hr. or that ran for more than 1,000 hours in any year since 2005. EPA should eliminate the conflict by modifying the language in the rule to match the Preamble and to emphasize Tier 4 calculation methodology must only be used for units that combust solid fuels or MSW and that meet the requirements in the subparagraphs. Section 98.33(b)(5)(i) through (iii) should be replaced with the following text: (5) The Tier 4 Calculation Methodology: (i) May be used for a unit of any size, combusting any type of fuel. (ii) Shall be used for a unit if: (A) The unit has a maximum rated heat input capacity greater than 250 mmBtu/hr, or if the unit combusts municipal solid waste and has a maximum rated input capacity greater than 250 tons per day of MSW, and (B) The unit combusts solid fossil fuel or MSW, either as a primary or secondary fuel, and (C) The unit has operated for more than 1,000 hours in any calendar year since 2005, or (D) The unit meets the criteria in (B) and (C) directly above, and (E) The unit has installed CEMS that are required either by an applicable Federal or State regulation or the unit's operating permit, and (F) The installed CEMS include a gas monitor of any kind, a stack gas volumetric flow rate monitor, or both and the monitors have been certified in accordance with the requirements of part 75 of this chapter, part 60 of this chapter, or an applicable State continuous monitoring program, and (G) The installed gas and/or stack gas volumetric flow rate monitors are required, by an applicable Federal or State regulation or the unit's operating permit, to undergo periodic quality assurance testing in accordance with appendix B to part 75 of this chapter, appendix F to part 60 of this chapter, or an applicable State continuous monitoring program. (iii) Shall be used for a unit with a maximum rated heat input capacity of 250 mmBtu/hr or less and for a unit that combusts municipal solid waste with a maximum rated input capacity of 250 tons of MSW per day or less, if the unit: (A) Has both a stack gas volumetric flow rate monitor and a CO_2 concentration monitor, and (B) The unit meets the other conditions specified in paragraphs (b)(5)(ii)(B) and (C) of this section, and (C) The CO_2 and stack gas volumetric flow rate monitors meet the conditions specified in paragraphs (b)(5)(ii)(D) through (b)(5)(ii)(F) of this section. Based on the EPA discussion in the Preamble to the proposed rule, BP is concerned that it is EPA's position that any CEM can be converted to a CO_2 CEM. The difficulty of converting an existing CEM to CO_2 is a function of a number of issues including existing metering and capacity. For this reason, clarification should be added to

Section 98.33(b)(5)(ii)(E) and (F) to indicate the "installed CEMS" are referring to existing CO_2 CEMS and not any type (i.e., criteria pollutant) of CEM.

Response: See the response to comment EPA-HQ-OAR-2008-0508-0455.1 excerpt 7 and the response to comment EPA-HQ-OAR-2008-0508-0580 excerpt 10 for EPA's rationale and approach to the use of CEMS.

EPA acknowledges the commenter's concerns regarding Tier 4 applicability. EPA has revised the rule to clarify that all six criteria specified in subparagraphs (A) through (F) must be met before Tier 4 is required. However, EPA disagrees with suggestions that Tier 4 should only be required if the installed CEMS include a CO_2 monitor. The Tier 4 CEMS requirement is limited to larger solid fossil fuel units with an existing pollutant CEMS or volumetric flow rate monitor. EPA is requiring the use of CEMS due to the complexity of monitoring solid fuel consumption and the heterogeneous nature of the solid fuels. Many of these fossil-fuel fired units with a pollutant CEMS have an existing diluent monitor (O_2 or CO_2) that can be used to determine CO_2 emissions. EPA's estimates of monitoring costs are averages for a representative facility and may not represent the actual cost in individual circumstances.

EPA acknowledges the commenter's concerns, and in the final rule has added language to clarify that all three conditions in §98.33 must be met before requiring the use of Tier 4.

Commenter Name: See Table 3
Commenter Affiliation:
Document Control Number: EPA-HQ-OAR-2008-0508-0433.2
Comment Excerpt Number: 64

Comment: The units of measure for the emission factors in Tables C-1 and C-3 should be in tonne/yr rather than kg/yr. Based on this, are the numerical values listed for these emission factors in Tables C-1 and C-3 correct since the units of measure are not consistent with the equations used in Subpart Y? The units of measure should be in tonnes/yr.

Response: EPA disagrees with the commenter, and believes the emission factors in the Subpart C tables are correct as written. The equations used in Subparts C and Y take emission factors in kg/mmBtu except where other default values are provided, and these are the units of the factors in the tables.

Commenter Name: Fiji George
Commenter Affiliation: El Paso Corporation
Document Control Number: EPA-HQ-OAR-2008-0508-0398.1
Comment Excerpt Number: 39

Comment: Sections 98.33(a)(2)(i) and 98.33(a)(3)(iii), specifically equations C-2a and C-5, require that CO_2 emissions be calculated using monthly fuel consumption and gas characteristic obtained on a monthly basis for Tier 2 and Tier 3, respectively. El Paso recommends, for units that use highly homogeneous fuels such as pipeline quality natural gas, the relevant equations be modified to allow using annual fuel volumes and annual average gas characteristics. Appendix IV provides a sample calculation of CO_2 emissions for natural gas fired units at an El Paso facility. [See DCN: EPA-HQ-2008-0508-0398.1] The emissions are calculated based on actual fuel consumption and actual gas properties using each methodology and then compared. As demonstrated by this example, the change in emissions resulting from methodology change is negligible considering fuel meter accuracy. However, this simplification will greatly reduce the cost of setting up the reporting systems. None of the states or voluntary programs to which El Paso is reporting emissions of criteria pollutants requires that the reporting data be based on monthly operating data. Therefore, most likely reporters using Tier 2 or Tier 3 for GHG reporting in accordance with this proposed regulation will not be able to build on the systems already in place but will have to develop new systems which are time and resource consuming (with very little benefit). The proposed simplification would reduce the time of setting up the reporting system about 6 times (two basic calculations instead of thirteen) without considerable impact on the quality of the reported emissions. In addition, the emissions of CH_4 and N_2O are required to be calculated based on annual fuel consumption. The above described change will allow using the same fuel basis for all pollutants resulting in even greater streamlining of the calculations.

Response: The mandatory monthly fuel sampling and analysis requirements for traditional fossil fuels have been dropped from Tiers 2 and 3. EPA agrees with the commenters that for a homogeneous fuel such as pipeline natural gas, monthly sampling is not necessary. For other fuels such as oil and coal, which are delivered in shipments or lots, requiring monthly sampling may be impractical; new fuel lots or deliveries may not be received on a monthly basis. Therefore, §98.34 has been revised to require that natural gas be sampled semiannually. For fuel oil and coal, a representative sampling is required for each fuel lot, i.e., for each shipment or delivery. For other liquid fuels and biogas, quarterly sampling is required. For other solid fuels, excluding municipal solid waste, weekly composite sampling with monthly analysis is required. For other gaseous fuels, the daily sampling requirement has been retained, but only for facilities with existing equipment in place that is capable of providing the data. Otherwise, weekly sampling is required, which may be postponed in favor of monthly sampling until 2011 if new equipment must be purchased or if existing equipment must be upgraded to meet the weekly sampling and analysis requirements.

The final rule clarifies that fuel sampling and analysis data provided by the supplier may be used in the emission calculations, and that fuel billing meters may be used to quantify fuel consumption. To simplify the emission calculations in Tiers 2 and 3, averaging of HHV and carbon content data is permitted if these data are obtained at least at the minimum frequency specified in §98.34. If the results of fuel sampling are received monthly or more frequently, the weighted annual average high heat value shall be calculated using Equation C-2b. If the results of fuel sampling are received less frequently than monthly, then the annual average HHV shall be calculated using the arithmetic average HHV for all valid samples for the year. However, regardless of the sampling frequency, the owner or operator must use the results of all available valid fuel analyses in the emissions calculations.

Commenter Name: See Table 3
Commenter Affiliation:
Document Control Number: EPA-HQ-OAR-2008-0508-0433.2
Comment Excerpt Number: 62

Comment: At §98.33(a)(4)(i), the proposal cites "paragraph (a)(1)(iv)(D) of this section." No such paragraph exists in the proposed rule. We request clarification or correction of this citation. Clarification on the Tiers for methodology in Subpart C is needed. Each of the conditions listed under Tier 4 (5)(ii) states that Tier 4 methodology "shall be used if", and then lists conditions labeled A,B,C,D,E,F. These conditions do not have punctuation, including "and"s or "or"s. NPRA proposes that they should be labeled "and" not "or" to show that all conditions must be met to be required to comply with the Tier 4 methodology. Currently the rule language is labeled neither. It is only implied to be "and".

Response: EPA acknowledges the commenter's concerns regarding Tier 4 applicability. EPA has revised §98.33(b) of the final rule to clarify that all six criteria specified in subparagraphs (A) through (F) must be met before Tier 4 is required. In addition, the paragraph referenced in the comment (§98.33(a)(4)(i) in the final rule) now refers to §98.33(a)(4)(iv).

Commenter Name: Marc J. Meteyer
Commenter Affiliation: Compressed Gas Association (CGA)
Document Control Number: EPA-HQ-OAR-2008-0508-0981.1
Comment Excerpt Number: 18

Comment: The proposed rule defines the applicability of the alternate calculation method "tiers" based on combustion unit size and availability of data, with a general trend to require more rigorous calculation methods (e.g. increasing from Tier 1 to Tiers 2, 3, and 4) for higher operating capacity units and facilities that currently employ certain process or emission measurements. This push for more rigorous calculation methods is made without regard for a) the underlying accuracy of the calculation method, b) the quality and completeness of existing process or emission measurement, or the cost of the necessary measurement equipment or practice. The result is a rule that often requires a costly, laborious measurement/calculation method that does not improve the accuracy or completeness of the emission estimate. In many instances, less rigorous calculation methods (e.g. "lower" Tiers) will yield comparable (or better) accuracy emission estimates, with higher reliability and at lower cost. There is an implied assumption that directly measured emissions will yield a better emission estimate. This presumption is not true, as evidenced by an acceptable level of (in)accuracy tolerance under CEMS certification/calibration procedures (> 5 - 7%) versus levels of fuel consumption metering employed for invoice billing (typically < 2%). CGA Comment: EPA should be more flexible as it relates to the applicability to the alternate combustion emission calculation methods. In particular: Allow use of the Tier 1 method for units of any size (currently restricted to units < 250 mmBTU/hr or less), particularly for standard fuels of commerce such as natural gas, LP gas and fuel oils, where billing-quality consumption data is accurate and readily available and the default HHV and CO_2 emission factors are well known constants (as noted in the Preamble for the proposed rule – natural gas carbon content is always within 1% of the default ratio). Recognize that a source's current practices of occasionally characterizing fuels for HHV or carbon content does not necessarily constitute having data "available" consistent with the compliance expectations of Tiers 2 and 3. Where Tiers 2 or 3 would be required, existing fuel characterization may not be according to the specified analytical methods or at the required frequency. Do not require Tier 2 or 3 where data fully meeting the defined compliance expectation is not currently being obtained. Do not require the use of the Tier 4 method where alternative fuel consumption data is available; allow optional use of the Tier 4 method at the source's discretion. This may be a suitable calculation method where a source uses multiple fuels and/or non-commercial fuels or where existing CEMS systems include CO_2 measurement or can be modified at lower cost than alternative fuel consumption and/or characterization devices/practices. In any case, let the regulated source determine which method is most cost effective for their particular situation. This option is available in California's GHG mandatory reporting program.

Response: See the Preamble, Section II. L., on General Monitoring Requirements for the overall rationale for methodologies required under this rule, and the response to comment EPA-HQ-OAR-2008-0508-0909.1 excerpt 4 and EPA-HQ-OAR-2008-0508-0580 excerpt 10 for the rationale for methodologies required under Subpart C.

EPA acknowledges the commenter's concerns, and has substantially revised §98.33(b) in the final rule, relaxing tier and calculation method applicability. EPA believes that the revised language makes it clear which tier calculation method(s) a reporter may use. The revised rule also adds considerable flexibility, allowing more reporters to use the lower tiers.

EPA has significantly expanded the use of Tier 1 and Tier 2 Calculation Methodologies. The monthly fuel sampling and analysis requirements for Tiers 2 and 3 have been considerably revised. Natural gas fired units are to be sampled semiannually. For fuel oil and coal, a representative sampling is required for each fuel lot, i.e., for each shipment or delivery. For other liquid fuels and biogas, quarterly sampling is required. For other solid fuels, excluding municipal solid waste, weekly composite sampling with monthly analysis is required. For other gaseous fuels, the daily sampling requirement has been retained, but only for facilities with existing equipment in place that is capable of providing the data. Otherwise, weekly sampling is required.

The final rule clarifies that fuel sampling and analysis data provided by the supplier may be used in the emission calculations, and that fuel billing meters may be used to quantify fuel consumption. To simplify the emission calculations in Tiers 2 and 3, averaging of HHV and carbon content data is permitted if these data are obtained at least at the minimum frequency specified in §98.34. If the results of fuel sampling are received monthly or more frequently, the weighted annual average high heat value shall be calculated using Equation C-2b. If the results of fuel sampling are received less frequently than monthly, then the annual average HHV shall be calculated using the arithmetic average HHV for all valid samples for the year. However, regardless of the sampling frequency, the owner or operator must use the results of all available valid fuel analyses in the emissions calculations.

The Tier 4 CEMS requirement is limited to larger solid fossil fuel units with an existing pollutant CEMS or volumetric flow rate monitor. EPA is requiring the use of CEMS due to the complexity of monitoring solid fuel consumption and the heterogeneous nature of the solid fuels. Many of these fossil-fuel fired units with a pollutant CEMS have an existing diluent monitor (O_2 or CO_2) that can be used to determine CO_2 emissions.

Commenter Name: Ron Downey
Commenter Affiliation: LWB Refractories
Document Control Number: EPA-HQ-OAR-2008-0508-0719.1
Comment Excerpt Number: 51

Comment: In Equation C-6 (40 C.F.R. 98.33), CO_2 = 5.18 x 10(-7) * C_{CO2} * Q needs to be clarified. This formula is similar to the formula listed in Appendix F of Part 75, except that the conversion factor in Part 75 is 5.7 x 10(-7). NLA requests clarification on why a different conversion factor was used in the Proposed Rule. Similarly, the unit label for C_{CO2} is not correct. It is shown as tons/scf - % CO_2, which is not mathematically correct. It should be corrected to show (tons/scf)/% CO_2 as shown in Appendix F of Part 75. Finally, this Equation should be clarified so that the % CO_2 concentration (term C_{CO2}) is not entered into the formula as a decimal fraction. For example, if the % CO_2 is 25% ,then 25 should be used in the formula, not 0.25. This is because the conversion factor is in units of (tons/scf)/% CO. This is misleading as most calculations using a percent call for the decimal fraction representation.

Response: EPA has corrected the unit label for the conversion factor. It now reads (metric tons/scf/% CO_2). EPA believes that the value of the conversion factor provided in Equation C-6 is accurate, given these revised units.

Commenter Name: Gregory A. Wilkins
Commenter Affiliation: Marathon Oil Corporation
Document Control Number: EPA-HQ-OAR-2008-0508-0712.1
Comment Excerpt Number: 50

Comment: EPA should be sure that in the final rule, that activity information and the time period for factor information are compatible. For example, a monthly sample should be multiplied by a monthly flow measurement, or the average of 12 monthly samples for factor data (carbon content) should be multiplied by the annual flow data. EPA needs to provide instructions on how reconciling the different time periods for activity data (flow) and factor data (sampling) should take place.

Response: EPA has substantially revised §98.33(a). The Tier 2 and Tier 3 methods now contain additional language clarifying how reporters are to reconcile the frequency of sample analysis with the period for which fuel flow data is taken. For example, if, under Tier 2, a unit determines the HHV of its fuel more than once a month, and has fuel consumption records for each month, the unit should average the multiple HHV determinations arithmetically to arrive at a single value for use in the calculation of emissions for that month. Similar specifications are provided for HHV determined less frequently than monthly and for Tier 3 calculations.

Commenter Name: Ron Downey
Commenter Affiliation: LWB Refractories
Document Control Number: EPA-HQ-OAR-2008-0508-0719.1
Comment Excerpt Number: 50

Comment: 40 C.F.R. 98.33(c)(4) refers to Table C-4, but no such table appears in the Proposed Rule.

Response: In the final rule, the proposed §98.33(c)(4) language has been deleted.

Commenter Name: Ron Downey
Commenter Affiliation: LWB Refractories
Document Control Number: EPA-HQ-OAR-2008-0508-0719.1
Comment Excerpt Number: 49

Comment: 40 C.F.R. 98.33(a)(1)(4)(i) refers to "(a)(1)(iv)(D) of this section," but NLA was unable to locate this provision. Did EPA intend to refer to 40 C.F.R. 98.33(a)(4)(i)?

Response: EPA has corrected this error. The paragraph referenced in the comment (§98.33(a)(4)(i) in the final rule) now refers to §98.33(a)(4)(iv).

Commenter Name: See Table 5
Commenter Affiliation:
Document Control Number: EPA-HQ-OAR-2008-0508-0480.1
Comment Excerpt Number: 43

Comment: In many cases, natural gas sector sources will have monthly high heating value (HHV) data and will thus fall under the Tier 2 calculation approach based on measured rather than default HHV. Similarly, Tier 3 requires monthly or more frequent fuel carbon content data. For natural gas transmission, there is typically little month-to-month or day-to-day variability in measured HHV or carbon content, but data tracking and report calculations will be more burdensome if emissions need to be calculated for each source for time scales shorter than annually. For sources with monthly (or more frequent) HHV or fuel carbon content measurement and little variation in the gas quality for those measurements, operators should have the option to complete the calculation annually based on the average of the twelve monthly (or more frequent) HHV or fuel carbon content measurements. This will reduce reporting burden without impacting report quality. For fuels such as pipeline quality natural gas that are relatively homogeneous over extended time periods, average annual HHV or carbon content should be allowed for calculating combustion emissions under Subpart C. If needed, a maximum relative variability could be specified for this approach. INGAA recommends a target of 10% or less variation in the measured HHV or carbon content relative to the annual average. In this case, operators should be allowed to calculate combustion emissions based on the annual average HHV or carbon content and annual fuel use. EPA should address this in §98.33 by clarifying that the annual average can be used for fuel volume and HHV in Equation C-2a for Tier 2 and for fuel volume and carbon content in Equation C-5 for Tier 3 gaseous fuels. A similar clarification should be added for Equation C-10a regarding the use of annual average HHV and annual fuel use for calculating annual combustion emissions of methane and nitrous oxide.

Response: EPA has added language in §98.33 clarifying that either the owner or operator or the fuel supplier may be responsible for the sampling and analysis for HHV. Section 98.34(a) further clarifies that the fuel sampling may be performed by the owner or operator, the fuel supplier, or an independent laboratory. EPA has also added flexibility to the use of the four tiers, and has reduced the frequency of required sampling for many fuels, including natural gas. To simplify the emission calculations in Tiers 2 and 3, averaging of HHV and carbon content data is permitted if these data are obtained at least at the minimum frequency specified in §98.34. If the results of fuel sampling are received monthly or more frequently, the weighted annual average high heat value shall be calculated using Equation C-2b. If the results of fuel sampling are received less frequently than monthly, then the annual average HHV shall be calculated using the arithmetic average HHV for all valid samples for the year. However, regardless of the sampling frequency, the owner or operator must use the results of all available valid fuel analyses in the emissions calculations. EPA has included similar equations for units combusting solid and liquid fuels using Tier 3. However, for gaseous fuels using Tier 3, EPA has decided to require facilities to use average carbon content determinations and fuel consumption for each measurement period (as specified in §98.34).

Commenter Name: Marc J. Meteyer
Commenter Affiliation: Compressed Gas Association (CGA)
Document Control Number: EPA-HQ-OAR-2008-0508-0981.1
Comment Excerpt Number: 43

Comment: CGA Comment: EPA should be more flexible as it relates to the applicability to the alternate combustion emission calculation methods. In particular: 1. Allow use of the Tier 1 method for units of any size (currently restricted to units < 250 mmBTU/hr or less), particularly for standard fuels of commerce such as natural gas, LP gas and fuel oils, where billing-quality consumption data is accurate and readily available and the default HHV and CO_2 emission factors are well known constants (as noted in the Preamble for the proposed rule – natural gas carbon content is always within 1% of the default ratio). 2. Recognize that a source's current practices of occasionally characterizing fuels for HHV or carbon content does not necessarily constitute having data "available" consistent with the compliance expectations of Tiers 2 and 3. Where Tiers 2 or 3 would be required, existing fuel characterization may not be according to the specified analytical methods or at the required frequency. Do not require Tier 2 or 3 where data fully meeting the defined compliance expectation is not currently being obtained. 3. Do not require the use of the Tier 4 method where alternative fuel consumption data is available. Allow optional use of the Tier 4 method where, at the source's discretion. This may be a suitable calculation method where a source uses multiple fuels and/or noncommercial fuels or where existing CEMS systems include CO_2 measurement or can be modified at lower cost than alternative fuel consumption and/or characterization devices/practices. In any case, let the regulated source determine which method is most cost effective for their particular situation. 4. Clarify the requirement to employ the Tier 4 calculation method. Resolve the apparent discrepancy between the intent to limit Tier 4 to only Solid Fossil Fuel fired combustion units, per Table C-1 of the Preamble, with the actual imposition of Tier 4 described under

§98.33(b)(5)(ii). Clarify that in order for Tier 4 to be required under §98.33(b)(5)(ii), all the conditions under §98.33(b)(5)(ii)(A), (B), (C), and (D) must be met. Specifically, conditions (A), (B), (C), and (D) should be separated by the word "and" – absent that, an implied "or" would force this calculation method on many other combustion units for which it was not intended. Further, do not require the use of the Tier 4 method where alternative fuel consumption data is available. Tier 1, 2, and 3 offer viable alternatives for many combustion sources that will yield comparable (and in many cases more) accurate emission estimates. Allow optional use of the Tier 4 method where, at the source's discretion. This may be a suitable calculation method where a source uses multiple fuels and/or non-commercial fuels or where existing CEMS systems include CO_2 measurement or can be modified at lower cost than alternative fuel consumption and/or characterization devices/practices. In any case, let the regulated source determine which method is most cost effective for their particular situation.

Response: See the Preamble, Section II. L., on General Monitoring Requirements for the overall rationale for methodologies required under this rule, and the response to comment EPA-HQ-OAR-2008-0508-0909.1 excerpt 4 and EPA-HQ-OAR-2008-0508-0580 excerpt 10 for the rationale for methodologies required under Subpart C.

EPA acknowledges the commenter's concerns, and has substantially revised §98.33(b) in the final rule, relaxing tier and calculation method applicability. EPA believes that the revised language makes it clear which tier calculation method(s) a reporter may use. The revised rule also adds considerable flexibility, allowing more reporters to use the lower tiers.

EPA has significantly expanded the use of Tier 1 and Tier 2 Calculation Methodologies. The monthly fuel sampling and analysis requirements for Tiers 2 and 3 have been considerably revised. Natural gas fired units are to be sampled semiannually. For fuel oil and coal, a representative sampling is required for each fuel lot, i.e., for each shipment or delivery. For other liquid fuels and biogas, quarterly sampling is required. For other solid fuels, excluding municipal solid waste, weekly composite sampling with monthly analysis is required. For other gaseous fuels, the daily sampling requirement has been retained, but only for facilities with existing equipment in place that is capable of providing the data. Otherwise, weekly sampling is required.

The final rule clarifies that fuel sampling and analysis data provided by the supplier may be used in the emission calculations, and that fuel billing meters may be used to quantify fuel consumption. To simplify the emission calculations in Tiers 2 and 3, averaging of HHV and carbon content data is permitted if these data are obtained at least at the minimum frequency specified in §98.34. If the results of fuel sampling are received monthly or more frequently, the weighted annual average high heat value shall be calculated using Equation C-2b. If the results of fuel sampling are received less frequently than monthly, then the annual average HHV shall be calculated using the arithmetic average HHV for all valid samples for the year. However, regardless of the sampling frequency, the owner or operator must use the results of all available valid fuel analyses in the emissions calculations.

The Tier 4 CEMS requirement is limited to larger solid fossil fuel units with an existing pollutant CEMS or volumetric flow rate monitor. EPA is requiring the use of CEMS due to the complexity of monitoring solid fuel consumption and the heterogeneous nature of the solid fuels. Many of these fossil-fuel fired units with a pollutant CEMS have an existing diluent monitor (O_2 or CO_2) that can be used to determine CO_2 emissions.

Commenter Name: Fiji George
Commenter Affiliation: El Paso Corporation
Document Control Number: EPA-HQ-OAR-2008-0508-0398.1
Comment Excerpt Number: 42

Comment: Section 98.33(c)(4) limits the use of alternative emission factors for natural gas because default factors are published in Table C-3. El Paso requests extending the flexibility and basis of N_2O and CH_4 emission factors to sources beyond Table C-3 and allowing emission factors from other GHG estimation guidelines. As demonstrated by the EPA emission inventory, the combined N_2O and CH_4 emissions in terms of CO_2e are less than one percent of the total GHG emissions from stationary combustion. Flexibility in selection of N_2O and CH_4 emission factors will allow facilities to meet multiple reporting obligations to states and/or voluntary registries that may require different or equipment/control technology-specific factors for these pollutants. For example, the State of New Mexico employs Intergovernmental Panel on Climate Change (IPCC) based emission factors to report N_2O and CH_4 from stationary combustion sources.

Response: EPA believes that default factors for listed fuel types in Subpart C are sufficient for reporting. EPA has clarified the rule to state that any emissions from unit startup or ignition, as well as from those fuels not listed in Table C-2 (formerly C-3), can be excluded from calculations of CH_4 and N_2O.

Commenter Name: Karen St. John
Commenter Affiliation: BP America Inc. (BP)
Document Control Number: EPA-HQ-OAR-2008-0508-0631.1
Comment Excerpt Number: 63

Comment: Section 98.38, Table C-3: CH_4 and N_2O factors should be provided for the following fuel types currently listed in §98.3 8, Table C-1: Ethane; Biogas; Isobutane; n-Butane; Natural Gasoline; Other Oil (> 401 def. F); Pentanes Plus; Petrochemical Feedstocks; Special Naphtha; and Unfinished Oils.

Response: In response to the comment, EPA has revised the default emission factors needed to calculate CH_4 and N_2O emissions, adding some of the emission factors suggested by commenters. EPA has clarified in the final rule that only CH_4 and N_2O emissions from combustion of those fuels listed in Table C-2 (formerly C-3) of Subpart C are required to be reported. Further, reporting of CH_4 and N_2O emissions is not required for fuels that are used exclusively for unit startup or ignition.

Commenter Name: Lorraine Krupa Gershman
Commenter Affiliation: American Chemistry Council (ACC)
Document Control Number: EPA-HQ-OAR-2008-0508-0423.2
Comment Excerpt Number: 80

Comment: There appears to be a typographical error in Table C-3. The word 'Tites' is possibly a misspelling of the word: 'Tires.'

Response: EPA has corrected this error in the final rule.

Commenter Name: Sam Chamberlain
Commenter Affiliation: Murphy Oil Corporation
Document Control Number: EPA-HQ-OAR-2008-0508-0625
Comment Excerpt Number: 24

Comment: EPA states in Sec. 98.33 Calculating GHG emissions: "(4) The Tier 3 Calculation Methodology may be used for a unit of any size, combusting any type of fuel, except when the use of Tier 4 is required or elected, as provided in paragraph (b)(5) of this section. (5) The Tier 4 Calculation Methodology: (i) May be used for a unit of any size, combusting any type of fuel. (ii) Shall be used for a unit if: (A) The unit has a maximum rated heat input capacity greater than 250 mmBtu/hr, or if the unit combusts municipal solid waste and has a maximum rated input capacity greater than 250 tons per day of MSW. (B) The unit combusts solid fossil fuel or MSW, either as a primary or secondary fuel. (C) The unit has operated for more than 1,000 hours in any calendar year since 2005. (D) The unit has installed CEMS that are required either by an applicable Federal or State regulation or the unit's operating permit. (E) The installed CEMS include a gas monitor of any kind, a stack gas volumetric flow rate monitor, or both and the monitors have been certified in accordance with the requirements of part 75 of this chapter, part 60 of this chapter, or an applicable State continuous monitoring program. The Tier 4 Calculation Methodology (5)(ii) implies that Tier 4 methodology shall be used for any unit that is: 1. greater than 250 MMBtu/hr, or 2. Combust solid fuel or MSW, or 3. Operated more than 1,000 hours in any calendar year since 2005, or 4. Unit has installed CEMS that are required by Federal or State Regulation or operating permit, or 5. The installed CEMS include a gas monitor of any kind, a stack gas volumetric flow rate monitor, or both and the monitors have been certified in accordance with the requirements of part 75 of this chapter, part 60 of this chapter, or an applicable State continuous monitoring program. This will automatically place every unit that has operated more than 1000 hours in a year regardless of size or fuel source will have to use Tier 4 Methodology. Also, that any unit that has a CEMS of any size will have to use Tier 4 Methodology. This is so broad that it will likely cause every source in the US to fall under Tier 4. Murphy recommends that the language be changed to the following: (4) The Tier 3 Calculation Methodology may be used for a unit of any size, combusting any type of fuel, except when the use of Tier 4 is required or elected, as provided in paragraph (b)(5) of this section. (5) The Tier 4 Calculation Methodology: (i) May be used for a unit of any size, combusting any type of fuel. (ii) Shall be used for a unit if: (A) The unit has a maximum rated heat input capacity greater than 250 mmBtu/hr, or if the unit combusts municipal solid waste and has a maximum rated input capacity greater than 250 tons per day of MSW, or (B) The unit combusts solid fossil fuel or MSW, either as a primary or secondary fuel and the unit has operated for more than 1,000 hours in any calendar year since 2005, or (C) The unit has installed CO_2 CEMS that are required either by an applicable Federal or State regulation or the unit's operating permit and a stack gas volumetric flow rate monitor and the monitors have been certified in accordance with the requirements of part 75 of this chapter, part 60 of this chapter, or an applicable State continuous monitoring program.

Response: EPA acknowledges the commenter's concerns regarding Tier 4 applicability. EPA has revised the rule to clarify that all six criteria must be met before Tier 4 is required. However, EPA disagrees with suggestions that Tier 4 should only be required if the installed CEMS include a CO_2 monitor. The Tier 4 CEMS requirement is limited to larger solid fossil fuel units with an existing pollutant CEMS or volumetric flow rate monitor. EPA is requiring the use of CEMS due to the complexity of monitoring solid fuel consumption and the heterogeneous nature of the solid fuels. Many of these fossil-fuel fired units with a pollutant CEMS have an existing diluent monitor (O_2 or CO_2) that can be used to determine CO_2 emissions.

Commenter Name: Kyle Pitsor
Commenter Affiliation: National Electrical Manufacturers Association (NEMA)
Document Control Number: EPA-HQ-OAR-2008-0508-0621.1
Comment Excerpt Number: 24

Comment: On page 16480 of the Preamble, although EPA notes that CO_2 emission generated by fuel combustion far exceeds the CH_4 and N_2O emissions (< 1% of total), EPA nevertheless has proposed that facilities must also estimate and report emissions of these two lesser GHGs. While the NEMA Carbon/Manufactured Graphite EHS Committee agrees that all combustion GHGs should be accounted for in the national GHG database for accuracy, it supports the use of a combined $CO_2/CH_4/N_2O$ emission factor used by some of the internationally recognized GHG emissions estimating protocols. This would simplify the calculation methods and reduce the burden on reporting facilities, without significantly compromising the accuracy of the emissions data.

Response: See the Preamble, Section II. C., and the response to comment EPA-HQ-OAR-2008-0508-0561.1 excerpt 2 for information on the rationale for reporting for CH_4 and N_2O.

See the response to comment EPA-HQ-OAR-2008-0508-0686.1 excerpt 25 for the rationale for reporting these gases separately.

EPA believes that using fuel-based default emission factors to report these gases separately provides an appropriate balance between easing the reporting burden on facilities and collecting useful data on GHG emissions.

Commenter Name: Robert Rouse
Commenter Affiliation: The Dow Chemical Company
Document Control Number: EPA-HQ-OAR-2008-0508-0533.1
Comment Excerpt Number: 23

Comment: Dow Suggests Revisions to 98.33(c)(4) Regarding the Calculation of CH_4 and N_2O Emission Factors. Dow notes that 98.33(c)(4) refers to Table C-4; however, there is no Table C-4. The correct reference appears to be Table C-3. In addition, Dow comments that the proposed process of conducting emission testing to determine site-specific CH_4 and N_2O emission factors via source testing will be an unwarranted cost to determine a very small emission factor. Either EPA should exclude these emissions from the reporting requirements or allow the owner/operator to estimate these emissions based on other factors and engineering estimations when the fuel combusted is not specifically listed in Table C-3.

Response: In the final rule, the proposed language in §98.33(c)(4) has been deleted.

EPA acknowledges the concerns of the commenter. However, EPA has decided to retain in the final rule the requirement to report CH_4 and N_2O from stationary combustion sources. EPA believes that the use of fuel-specific emission factors for these pollutants strikes an appropriate balance between minimizing the burden on reporters and obtaining valuable GHG emission data. EPA has, however, revised the final rule to exclude CH_4 and N_2O emissions from fuels for which the rule does not provide emission factors, and has deleted the provision allowing the owner or operator of a facility to develop site-specific emission factors for such fuels. EPA believes that this change will reduce the reporting burden on facilities.

Commenter Name: Patrick J. Nugent
Commenter Affiliation: Texas Pipeline Association (TPA)
Document Control Number: EPA-HQ-OAR-2008-0508-0460.1
Comment Excerpt Number: 23

Comment: Proposed §98.33(b)(5)(ii) should be written more precisely. Proposed §98.33(b)(5)(ii) lists all of the requirements that must be met in order for Tier 4 to apply. The requirements listed in (A) – (F) of proposed §98.33(b)(5)(ii) should make clear that all of those requirements must be met for Tier 4 to be required. TPA suggests that the word "and" be placed between (E) and (F) in order to make this clear.

Response: EPA acknowledges the commenter's concerns regarding Tier 4 applicability. EPA has revised the rule to clarify that all six criteria must be met before Tier 4 is required.

Commenter Name: Kyle Pitsor
Commenter Affiliation: National Electrical Manufacturers Association (NEMA)
Document Control Number: EPA-HQ-OAR-2008-0508-0621.1
Comment Excerpt Number: 23

Comment: If a facility opts to combine all its combustion units that are supplied by a common gaseous or liquid fossil fuel supply piping configuration, which is equipped with a calibrated fuel flow meter, for the purpose of simplifying its emissions calculations, the NEMA Carbon/Manufactured Graphite EHS Committee understands the facility can do this regardless of the total number of units or regardless of the total maximum rated heat input capacity of the individual units or of the entire group. The NEMA Carbon/Manufactured Graphite EHS Committee agrees this is an acceptable option. However, since EPA is not restricting the total maximum rated heat input capacity of the combined units, the NEMA Carbon/Manufactured Graphite EHS Committee believes that the facility should not be required to use the Tier 3 method to calculate CO_2 emissions for any combustion unit > 250 mmBtu/hr. and that this requirement should also not apply to these aggregated combustion units, where any one or more of the units, or the total group of units exceeds this maximum rated heat input capacity. This would potentially negate much of the main reason for aggregating multiple units, which is to simplify the GHG emission calculations, if the facility would now have to use the more complex calculation method for the entire group, requiring either daily or monthly measurements and calculations. For the same reason already mentioned above, a fact to which EPA readily admits in the Preamble, commercially-available gaseous and liquid fuels are typically homogenous so there should be an insignificant variability in the carbon content. That fact coupled with the expected accuracy of the typical supplier billing meter on common fuel supply piping, indicates there would be no significant benefit to requiring the more onerous Tier 3 calculation method to estimate GHG emissions for an aggregated group of units even if the total (or any of the individual unit) maximum heat input capacity exceeds 250 mmBTU/hr. On page 16484 of the Preamble under the discussion of Tier 1, EPA states it "considered" allowing the use of default emission factors, default HHVs and company records to quantity annual fuel consumption for all stationary combustion units, regardless of size or the type of fuel combusted, but "decided to limit the use of this type of calculation methodology to smaller combustion units". However, EPA provides absolutely no justification for this decision, which unnecessarily complicates the emissions estimation procedures. Given the additional burden on reporting facilities, and the arguments provided above, the NEMA Carbon/Manufactured Graphite EHS Committee requests that EPA allow this simplified and generally accepted Tier 1 estimation procedure in the final rule for all stationary combustion units regardless of size or the type of fuel combusted, at a minimum to quantify annual consumption for commercially-available gaseous and liquid fuels that have established default emission factors and HHVs.

Response: The final rule significantly expands the use of the Tier 1 and Tier 2 Calculation Methodologies. The 250 mmBtu/hr restriction on the use of Tier 2 has been lifted for units that combust natural gas and distillate oil, in view of the homogeneous nature and low variability in the characteristics of these fuels. The monthly fuel sampling and analysis requirements for Tiers 2 and 3 have been considerably revised. Natural gas fired units are to be sampled semiannually. For fuel oil and coal, a representative sampling is required for each fuel lot, i.e., for each shipment or delivery. For other liquid fuels and biogas, quarterly sampling is required. For other solid fuels, excluding municipal solid waste, weekly composite sampling with monthly analysis is required. For other gaseous fuels, the daily sampling requirement has been retained, but only for facilities with existing equipment in place that is capable of providing the data. Otherwise, weekly sampling is required.

For units that use Tiers 1, 2, and 3 to calculate CO_2 mass emissions, the cumulative 250 mmBtu/hr heat input capacity limit on the aggregation of units into a group has been dropped. Rather, the 250 mmBtu/hr restriction applies only to the individual units in the group. Therefore, for reporting purposes, individual units with maximum rated heat input capacities of 250 mmBtu/hr or less may be aggregated without limit into a single group, provided that the Tier 4 methodology is not required for any of the units, and all units in the group use the same tier for any common fuel(s) that they combust. Units with maximum rated heat inputs greater than 250 mmBtu/hr using Tiers 1, 2, and 3 must report as individual units, unless they burn the same type of fuel provided by a common pipe or supply line; in that case, the owner or operator may opt to use the common pipe reporting provisions in §98.36(c)(3).

Commenter Name: Sean M, O'Keefe
Commenter Affiliation: Hawaiian Commercial and Sugar Company (HC&S)
Document Control Number: EPA-HQ-OAR-2008-0508-1138.1
Comment Excerpt Number: 8

Comment: In the proposed rule, EPA has selected Option 2 (combination of direct measurement and facility-specific calculations) as the general monitoring approach. Our comments above notwithstanding, if this option is adopted in the final rule, then the language of the rule needs to be revised to clarify when the use of CEMS for monitoring carbon dioxide emissions is mandatory and when it is optional. Specifically, the proposed §98.33(b)(5) specifies when the Tier 4 calculation methodology (i.e., calculating emissions from all fuels combusted in a unit by using data from CEMS) may be used by general stationary fuel combustion sources and when it shall be used. The current language is not clear regarding whether the Tier 4 methodology must be used when all of the conditions listed in §§98.33(b)(5)(ii)(A) through (F) are met or when any one of the conditions is met; the language should be modified to make clear that all of the conditions must be met (e.g., by adding the word "and" prior to §98.33(b)(5)(ii)(F)). Similarly, the proposed §98.33(b)(5)(iii) should state that use of the Tier 4 methodology is mandatory only if all of the conditions listed in §§98.33(b)(5)(iii)(A) through (C) are met (again, the word "and" could be added prior to §98.33(b)(5)(iii)(C)).

Response: EPA acknowledges the commenter's concerns regarding Tier 4 applicability. EPA has revised the rule to clarify that all six criteria must be met before Tier 4 is required.

Commenter Name: Edgar O. Morris
Commenter Affiliation: Mosaic Fertilizer Company LLC
Document Control Number: EPA-HQ-OAR-2008-0508-0687.1
Comment Excerpt Number: 6

Comment: The proposal prescribes a specific methodology for calculating GHG emissions that warrants clarification regarding the requirements for continuous emissions monitoring systems ("CEMS"). See proposed 40 C.F.R. §98.33. As EPA explained in the Preamble to the proposal, these methodologies are identified as "Tiers" 1 through 4, where each "Tier" involves increasing complexity, detail and cost, and applies to larger and more complicated sources with larger emissions for which a generic calculation would be more difficult (due to the type of fuel) and where more investment is warranted. See proposed 40 C.F.R. §98.33(a)(1) through (4); see also 74 Fed. Reg. at 16,483 - 16484. Tier 4 is the most prescriptive and potentially burdensome methodology. Compliance with Tier 4, rather than Tier 3, is in many instances substantial, since Tier 4, requires, among other things, "a CO_2 concentration monitor and a stack gas volumetric flow rate monitor." See proposed 40 C.F.R. §98.33(a)(4)(i). Tier 4 requirements apply to units satisfying a number of criteria, including that the unit "has installed CEMS that are required either by an applicable Federal or State regulation or the unit's operating permit", see proposed 40 C.F.R. §98.33(b)(5)(ii)(D), and that "The installed CEMS include a gas monitor of any kind, a stack gas volumetric flow rate monitor, or both". See proposed 40 C.F.R. §98.33(b)(5)(ii)(E). The NPRM defines CEMS broadly to include "the total equipment required to sample, analyze, measure and provide, by means of readings recorded at least once every 15 minutes, a permanent record of gas concentrations, pollutant emission rates, or gas volumetric flow rates from stationary sources." See proposed 40 C.F.R. §98.6. Accordingly, Tier 4 requirements may apply broadly to units with pre-existing CEMS. The proposed rule language is unclear as to whether a unit must satisfy all of the criteria listed under the proposed Sections 98.33(b)(5)(ii) or (iii) (by use of the word "and"), or whether Tier 4 requirements apply to units satisfying any one of these requirements (by use of the word "or"). Table C-1 of the Preamble indicates that the Tier 4 methodology is primarily used for large units combusting solid fuels and/or municipal solid wastes. See 74 Fed. Reg. at 16,481. The Preamble discussion also seems to indicate that all of the requirements of Sections 98.33(b)(5)(ii) or (iii) (depending on whether the unit has a maximum rated heat capacity of 250 mmBtu/hr or more) must apply before Tier 4 monitoring is required. See 74 Fed. Reg. at 16,483. Mosaic proposes that EPA add the conjunctive word "and" at the end of subpart (E), and semi-colons in place of periods after each subpart (A) through (E) in Section 98.33(b)(5)(ii); and similarly add the word "and" at the end of subpart (B), and semi-colons in place of periods in subparts (A) and (B) in Section 98.33(b)(5)(iii).

Response: EPA acknowledges the commenter's concerns regarding Tier 4 applicability. EPA has the rule to clarify that all six criteria must be met before Tier 4 is required.

See the response to comment EPA-HQ-OAR-2008-0508-0455.1 excerpt 7 and the response to comment EPA-HQ-OAR-2008-0508-0580 excerpt 10 for EPA's rationale and approach to the use of CEMS.

Many of these fossil-fuel fired units with a pollutant CEMS have an existing diluent monitor (O_2 or CO_2) that can be used to determine CO_2 emissions. EPA's estimates of monitoring costs are averages for a representative facility and may not represent the actual cost in individual circumstances.

Commenter Name: Marc J. Meteyer
Commenter Affiliation: Compressed Gas Association (CGA)
Document Control Number: EPA-HQ-OAR-2008-0508-0981.1
Comment Excerpt Number: 19

Comment: The proposed rule imposes the Tier 4 calculation methodology on sources meeting the conditions specified under §98.33(b)(5)(ii). As worded, it appears any one of the (A), (B), (C), or (D) conditions would result in the Tier 4 method being required. This does not match the intent expressed in the Preamble to the proposed rule, and summarized in Preamble table C-1. In particular, Table C-1 appears to indicate that Tier 4 is required only for Solid Fossil Fuel fired units > 250 mmBTU/hr (meeting other criteria, as well) and that Gaseous Fossil Fuel fired and Liquid Fossil Fuel fired combustion units are required to use no more rigorous than Tier 3 methods. The current language of §98.33(b)(5)(ii) would imply any of the conditions described in §98.33(b)(5)(ii)(A), (B), (C) or (D) trigger the Tier 4 method requirement. We believe the agency's intent is that all of the conditions described in §98.33(b)(5)(ii)(A), (B), (C) and (D) are necessary in order to trigger the Tier 4 method requirement. In addition, §98.33(b)(5)(ii)(E) imposes the Tier 4 method if the source has any existing CEMS system. Depending on the type of gas monitoring system a source may have (extractive vs. in-situ; wet vs. dry, etc.) the addition of a CO_2 CEMS can be a very costly modification. Modifications could include, assuming it is even technically feasible, the addition of stack sampling ports, addition of extractive sampling systems, sample conditioning systems, calibration gas systems and modification to data acquisition and reporting systems and software. Based on CGA member company experience these modifications can impose $40,000 to $250,000 of capital costs, as well as ongoing maintenance and operating costs for such units. As stated above, these costs may be imposed on the false premise that direct emission measurement via CEMS is an inherently more accurate than alternative calculation methods (e.g. Tiers 1, 2, or 3). CGA Comment: Clarify the requirement to employ the Tier 4 calculation method. Resolve the apparent discrepancy between the intent to limit Tier 4 to only Solid Fossil Fuel fired combustion units, per Table C-1 of the Preamble, with the actual imposition of Tier 4 described under §98.33(b)(5)(ii). Clarify that in order for Tier 4 to be required under §98.33(b)(5)(ii), all the conditions under §98.33(b)(5)(ii)(A), (B), (C), and (D) must be met. Specifically, conditions (A), (B), (C), and (D) should be separated by the word "and" – absent that, an implied "or" would force this calculation method on many other combustion units for which it was not intended. Further, do not require the use of the Tier 4 method where alternative fuel consumption data is available. Tier 1, 2, and 3 offer viable alternatives for many combustion sources that will yield comparable (and in many cases more) accurate emission estimates. Allow optional use of the Tier 4 method where, at the source's discretion. This may be a suitable calculation method where a source uses multiple fuels and/or non-commercial fuels or where existing CEMS systems include CO_2 measurement or can be modified at lower cost than alternative fuel consumption and/or characterization devices/practices. In any case, let the regulated source determine which method is most cost effective for their particular situation.

Response: EPA acknowledges the commenter's concerns regarding Tier 4 applicability. EPA has revised the rule to clarify that all six criteria must be met before Tier 4 is required. The Tier 4 CEMS requirement is limited to larger solid fossil fuel units with an existing pollutant CEMS or volumetric flow rate monitor.

See the response to comment EPA-HQ-OAR-2008-0508-0455.1 excerpt 7 and the response to comment EPA-HQ-OAR-2008-0508-0580 excerpt 10 for EPA's rationale and approach to the use of CEMS.

Many of these fossil-fuel fired units with a pollutant CEMS have an existing diluent monitor (O_2 or CO_2) that can be used to determine CO_2 emissions. EPA's estimates of monitoring costs are averages for a representative facility and may not represent the actual cost in individual circumstances.

Commenter Name: John M. McManus
Commenter Affiliation: American Electric Power
Document Control Number: EPA-HQ-OAR-2008-0508-0725.1
Comment Excerpt Number: 5

Comment: The CH_4 and N_2O emission factors presented in Table C-3 of subpart C (Default CH_4 and N_2O Emission Factors for Various Types of Fuel) are not consistent with EPA's AP-42 emission factors that are historically used for regulatory reporting. In particular, CH_4 emission rates in Table C-3 are significantly higher (although a footnote to Table C-3 may address this). AEP requests that EPA clearly authorize the use of the existing AP-42 emission factors for purposes of GHG reporting from EGUs, or provide a reasoned explanation of the basis for any alternative emission factors required by the rules.

Response: EPA believes the fuel types and respective default emission factors listed in Subpart C are sufficient for reporting. For the purposes of the rule, which is data collection for policy development, we would prefer consistent use of default CH_4 and N_2O emission factors. In this case, we provide the values we would like reporters to use in Subpart C, and for verification purposes, would prefer consistent use of these factors. Additional factors have been added as a result of comments. EPA is using mostly IPCC values in Table C-3 because we are aware that the AP-42 non-CO_2 factors haven't been reviewed in-depth recently.

Commenter Name: Sarah B. King
Commenter Affiliation: DuPont Company
Document Control Number: EPA-HQ-OAR-2008-0508-0604.1
Comment Excerpt Number: 26

Comment: According to the formulas provided in §98.33(c), only a fraction of a percent of the greenhouse gas emissions from combustion would be CH_4 or N_2O. Therefore, EPA should not require calculation and reporting of these emissions because their contribution to the total is insignificant.

Response: See the Preamble, Section II. C., and the response to comment EPA-HQ-OAR-2008-0508-0561.1 excerpt 2 for information on the rationale for reporting for CH_4 and N_2O.

EPA believes that the use of fuel-specific emission factors for these pollutants strikes an appropriate balance between minimizing the burden on reporters and obtaining valuable GHG emission data. EPA has, however, revised the final rule to exclude CH_4 and N_2O emissions from fuels for which the rule does not provide emission factors, and has deleted the provision allowing the owner or operator of a facility to develop site-specific emission factors for such fuels. EPA believes that this change will reduce the reporting burden on facilities.

Commenter Name: Lorraine Krupa Gershman
Commenter Affiliation: American Chemistry Council (ACC)
Document Control Number: EPA-HQ-OAR-2008-0508-0423.2
Comment Excerpt Number: 79

Comment: It is difficult to match the "fuel types" listed in Table C-3 to the "fuel types" listed in Tables C-1 and C- 2. This results because there are "fuel types" in Tables C-1 and C-2 that do not readily appear to have a counterpart "fuel type" in Table C-3. Examples are "coke," "ethane," "petrochemical feedstocks," "unfinished oils," "plastics" and "solvents" among others. Does this imply that reporting entities do not need to report Table C-3 emissions from these fuel types? There are also "fuel types" in Table C-3 that do not appear to have a counterpart "fuel type" in Tables C-1 and C-2. Examples are "digester gas," "landfill gas," "natural gas liquids" and "refinery gas."

Response: EPA acknowledges the concerns of the commenters. The tables in Subpart C have been substantially revised in the final rule. Table C-1 has been expanded to include all fuels for which CO_2 emissions must be calculated and reported for facilities using the Tier 1 and Tier 2 Calculation Methodologies. Table C-2 has been deleted, and a revised C-3 is now called C-2. Table C-2 includes all fuels for which CH_4 and N_2O emissions must be calculated and reported.

Commenter Name: Lorraine Krupa Gershman
Commenter Affiliation: American Chemistry Council (ACC)
Document Control Number: EPA-HQ-OAR-2008-0508-0423.2
Comment Excerpt Number: 78

Comment: There is an entry for 'Landfill gas' in Table C-3 of Subpart C and that term is defined in §98.6. However, there is no entry for 'Landfill gas' in either Tables C-1 or C-2.

Response: EPA acknowledges the concerns of the commenters. The tables in Subpart C have been substantially revised in the final rule. Table C-1 now includes biogas (captured methane).

Commenter Name: Lorraine Krupa Gershman
Commenter Affiliation: American Chemistry Council (ACC)
Document Control Number: EPA-HQ-OAR-2008-0508-0423.2
Comment Excerpt Number: 58

Comment: In §98.33(c)(4), it is not clear what EPA would be approving. As written, it appears that EPA would approve whether a company can develop its own site-specific emission factors (EFs); however, if no EFs are provided for its site-specific or unit-specific fuels, the company must calculate its own EFs. Thus, no EPA approval should be required. A more appropriate approach would be that EPA may audit a site's specific EFs for calculation validity. Furthermore, source testing will be an unwarranted cost to determine a very small emission factor. Either EPA should exclude these emissions from the reporting requirements or allow the owner/operator to estimate these emissions based on other factors and engineering estimations when the fuel combusted is not specifically listed in Table C-3.

Response: EPA has excluded fuels that are not listed with default CH_4 and N_2O factors in Subpart C, from the calculations of CH_4 and N_2O emissions.

Commenter Name: Lorraine Krupa Gershman
Commenter Affiliation: American Chemistry Council (ACC)
Document Control Number: EPA-HQ-OAR-2008-0508-0423.2
Comment Excerpt Number: 57

Comment: Section 98.33(c)(4) refers to Table C-4; however, there is no Table C-4. The correct reference appears to be Table C-3.

Response: In the final rule, the proposed language in §98.33(c)(4) has been deleted.

Commenter Name: Lorraine Krupa Gershman
Commenter Affiliation: American Chemistry Council (ACC)
Document Control Number: EPA-HQ-OAR-2008-0508-0423.2
Comment Excerpt Number: 55

Comment: The criteria for when Tier 4 is required are confusing as written and we cannot determine whether it is only required for MSW or solid fuel, or if it applies to other large (~ 250 MMBtu/hr) combustion units with liquid or gaseous fuels. In addition, the other criteria for MSW and solid fuels listed in Tier 4 are also confusing. We recommend that EPA clarify the Tier 4 requirements as follows: (1) Incorporate Table C-1 from page 16481 of the Federal Register containing the Preamble into the actual final rule. (2) Include the following excerpt from Page 16483 of the Preamble into the final rule, "The Tier 4 method, and the use of CEMS (with any required monitored upgrades) is required for solid fossil fuel-fired units with a maximum heat input capacity greater than 250 MMBtu/hr (and for units with a capacity greater than 250 tons per day of MSW)." (3) In §98.33(b)(5)(ii), include the word 'and' at the end of each item (A) through (F) to clarify that each one is required and that EPA did not mean 'or' between these items. (4) In §98.33(b)(5)(iii), include the word ³and´ at the end of each item (A) through (C) to clarify that each one is required and that EPA did not mean ³or´ between these items. There may be additional ways to improve the clarity of the applicability of the Tier 4 measuring requirements in §98.33(b)(5). ACC encourages EPA to find additional ways to improve the clarity of this alternative. It is important that facilities be able to interpret this part easily due to the costliness of installing and operating the CEMS equipment.

Response: EPA acknowledges the commenter's concerns regarding Tier 4 applicability. The Agency has revised §98.33of the final rule to clarify that all six criteria must be met before Tier 4 is required.

Commenter Name: Leslie Bellas
Commenter Affiliation: National Lime Association (NLA)
Document Control Number: EPA-HQ-OAR-2008-0508-0520.1
Comment Excerpt Number: 54

Comment: 40 C.F.R. §§98.33(a)(1) and (2) Should be Consistent with the Preamble, which Permits Tier 1 and Tier 2 Facilities to Use the High Heat Value Obtained from Fuel Supply Vendors.

Response: The final rule clarifies that fuel sampling and analysis data provided by the supplier may be used in the emission calculations, and that fuel billing meters may be used to quantify fuel consumption. To simplify the emission calculations in Tiers 2 and 3, averaging of HHV and carbon content data is permitted if these data are obtained at least at the minimum frequency specified in §98.34, but less frequently than monthly (see Equation C-2b). However, regardless of the sampling frequency, the owner or operator must use the results of all available valid fuel analyses in the emissions calculations.

Commenter Name: Leslie Bellas
Commenter Affiliation: National Lime Association (NLA)
Document Control Number: EPA-HQ-OAR-2008-0508-0520.1
Comment Excerpt Number: 53

Comment: 40 C.F.R. §§98.33(b)(5)(iii)(A) - (C) sets forth conditions for use of the Tier 4 methodology by units with a maximum rated heat input capacity of 250 mmBtu/hr or less and for units that combust municipal solid waste. To clearly indicate that all three conditions must be met before requiring use of the Tier 4 emission calculation methodology, each condition in 40 C.F.R. §§98.33(b)(5)(iii)(A) - (C) should end with a semi-colon, and that after the semicolon in 40 C.F.R. §98.33(b)(5)(iii)(B), the word "and" should be added.

Response: EPA acknowledges the commenter's concerns regarding Tier 4 applicability. EPA has revised the applicability in the final rule to clarify that all criteria must be met before Tier 4 is required.

Commenter Name: Lawrence W. Kavanagh
Commenter Affiliation: American Iron and Steel Institute (AISI)
Document Control Number: EPA-HQ-OAR-2008-0508-0695.1
Comment Excerpt Number: 6

Comment: With respect to potential applicability of Tier 4, which we understand to apply to large, solid fuel-fired combustion units, §98.33(b)(5) requires clarification. That paragraph should be amended to make clear that all six criteria set forth in subsections (A) - (F) must be met to trigger Tier 4 monitoring obligations. This section was apparently drafted to establish a six-part test for Tier 4 requirements, but as drafted the six criteria are stated independently. This understanding is further substantiated by language in the Preamble that makes clear that Tier 4 applies to solid fossil-fired units over 250 MMBTUH. EPA should clarify §98.33(b)(5) by inserting semicolons instead of periods after subparagraphs (A) - (E) and adding the word "and" after subparagraph (E).

Response: EPA acknowledges the commenter's concerns regarding Tier 4 applicability. EPA has revised the rule to clarify that all six criteria specified in subparagraphs (A) through (F) must be met before Tier 4 is required.

Commenter Name: Sean M, O'Keefe
Commenter Affiliation: Hawaiian Commercial and Sugar Company (HC&S)
Document Control Number: EPA-HQ-OAR-2008-0508-1138.1
Comment Excerpt Number: 10

Comment: Table C-1 of the proposed rule provides default CO_2 emission factors and high heat values for various types of fuel, including "wood and wood waste (12% moisture) or other solid biomass-derived fuels". These factors are to be used when estimating carbon dioxide emissions using the Tier 2 or Tier 1 methods. The default high heat value specified for "other solid biomass fuels" is not appropriate for sugarcane bagasse, the fiber remaining after sugarcane is milled which is the primary fuel burned in sugar mill boilers. Although sugarcane fiber has a range of heat values similar to those of other biomass fuels, such as wood, the moisture content of bagasse as burned is typically in the range of 45 to 55 percent. As a result, a more appropriate default high heat value for sugarcane bagasse (at 50% moisture content) would be approximately 8.3 MMBTU/short ton. At a typical carbon content of 49% (dry basis), an appropriate default CO_2 emission factor for sugarcane bagasse would be 98.39 kg CO_2/MMBTU. These values should be incorporated into Table C-1, since use of the existing default values for "other solid biomass-derived fuels" would result in significant overestimation of GHG emissions per ton of sugarcane bagasse combusted.

Response: EPA is allowing reporters to use the Tier 1 method when calculating CO_2 emissions from the combustion of biomass fuels, and provides default heating values and emission factors. Reporters may elect to use a higher tier method at their choice, such as Tier 3 which requires carbon content testing or the Tier 4 method which requires continuous monitoring of CO_2 emissions by a CEMS.

Commenter Name: See Table 6
Commenter Affiliation:
Document Control Number: EPA-HQ-OAR-2008-0508-0679.1
Comment Excerpt Number: 119

Comment: §98.38, Table C-3. Certain factors do not match those presented in the 2006 IPCC Guidelines for National Greenhouse Gas Inventories, when converted to a HHV basis. Factors should be revised as follows: a. Coal CH_4 factor of 1.0×10^{-2} should be 1.0×10^{-3}; b. Landfill Gas CH_4 factor of 9.0×10^{-4} should be 9.5×10^{-4}; c. Landfill Gas N_2O factor of 1.0×10^{-4} should be 9.5 x 10^{-5}; d. Natural Gas and Refinery Gas CH_4 factor of 9.0 x 10^{-4} should be 9.5 x 10^{-4}; and e. Natural Gas and Refinery Gas N_2O factor of 1.0 x 10^{-4} should be 9.5 x 10^{-5}.

Response: EPA believes the fuel types and respective emission factors listed in Subpart C are sufficient for reporting. EPA has reviewed the HHV values, and finds that they are consistent with Climate Leaders. Any values brought in from IPCC were converted in the same manner as the Climate Leaders factors. EPA is using mostly IPCC values in Table C-2 because we are aware that the AP-42 non-CO_2 factors haven't been reviewed in-depth recently.

Commenter Name: Kyle Pitsor
Commenter Affiliation: National Electrical Manufacturers Association (NEMA)
Document Control Number: EPA-HQ-OAR-2008-0508-0621.1
Comment Excerpt Number: 18

Comment: The Tier 4 Calculation Method under §98.33(4) is highly burdensome and the required continuous emissions monitoring system (CEMS) is both expensive to install and maintain. Therefore, this method should only be required of reporting facilities that are already required to operate such emissions monitoring equipment under existing rules promulgated under the CAA. The primary purposes of the Mandatory Greenhouse Gas Reporting Rule are to establish a reasonably accurate GHG emissions baseline for the U.S. for use in future rulemaking, and to establish standard procedures to ensure consistent GHG emissions data from year to year for tracking purposes. Given the significant recordkeeping and maintenance burdens associated with operating and maintaining CEMS, the higher level of accuracy afforded by these monitoring systems is neither necessary nor justified by the intended purposes of this rule. If a facility is not required to have CEMS under a Title V Permit for listed priority and hazardous air pollutants, or other CAA programs, because other emissions monitoring and/or estimation methods were deemed adequate, it makes little sense for such a facility to now have to install CEMS to report GHG emissions, when there are adequate methods available to reasonably and consistently estimate these emissions without adding excessive costs and the need for additional resources to install, operate and maintain these monitoring devices.

Response: EPA thanks you for your comment. See the Preamble and separate comment response document volume for the response on the general monitoring approach.

EPA acknowledges the commenter's concerns regarding Tier 4 applicability. EPA has revised the rule to clarify that all six criteria must be met before Tier 4 is required. The Tier 4 CEMS requirement is limited to larger solid fossil fuel units with an existing pollutant CEMS or volumetric flow rate monitor.

See the response to comment EPA-HQ-OAR-2008-0508-0455.1 excerpt 7 and the response to comment EPA-HQ-OAR-2008-0508-0580 excerpt 10 for EPA's rationale and approach to the use of CEMS.

Many of these fossil-fuel fired units with a pollutant CEMS have an existing diluent monitor (O_2 or CO_2) that can be used to determine CO_2 emissions. EPA's estimates of monitoring costs are averages for a representative facility and may not represent the actual cost in individual circumstances.

Commenter Name: See Table 10
Commenter Affiliation:
Document Control Number: EPA-HQ-OAR-2008-0508-0635
Comment Excerpt Number: 17

Comment: The reporting rule should more clearly require new facilities built with CEMS, or existing facilities which acquire CEMS, to use those CEMS (upgraded if necessary) to monitor GHG emissions. EPA should take advantage of facilities with CEMS, whenever they are built, rather than limiting the CEMS requirement just to facilities using that technology on the rule's effective date. EPA states in the Preamble that it intends to "require direct measurement of emissions from units at facilities that already are required to collect and report data using CEMS under other Federally enforceable programs."[112] A few paragraphs later, it again writes that "facilities that already use CEMS would still be required to use them."[113] These sentences are somewhat unclear: Does EPA intend to require GHG CEMS only of facilities that 'already are' using CEMS for some purpose when the rule first goes into effect, or does it intend that new facilities – either those whose emissions are below the reporting threshold in 2010, or which simply have not been built – be required to use GHG CEMS if they have a CEMS at all? The temporal baseline for the CEMS rule is not plainly specified. Unfortunately, this ambiguity is not limited to the Preamble. The rule's text also does not state a clear baseline, although it favors using CEMS whenever they are installed. The rule is clearly intended to apply to new sources – it includes provisions specifying reporting dates "for new facilities that commence operation on or after January 1, 2010" and for facilities which "become subject to this rule because of a physical or operational change" after that date114 -- but it does not include a clear directive to these sources explaining whether and how they could trigger CEMS requirements. The core CEMS provision, proposed 40 C.F.R. §98.33(b)(5)(ii), which is located within subpart C, covering general stationary fuel combustion sources provides that CEMS "[s]hall be used for a unit" if: A) The unit has a maximum rated heat input capacity greater than 250 mmBtu/hr, or if the unit combusts municipal solid waste and has a maximum rated input capacity greater than 250 tons per day of MSW. (B) The unit combusts solid fossil fuel or MSW, either as a primary or secondary fuel. (C) The unit has operated for more than 1,000 hours in any calendar year since 2005. (D) The unit has installed CEMS that are required either by an applicable Federal or State regulation or the unit's operating permit. (E) The installed CEMS include a gas monitor of any kind, a stack gas volumetric flow rate monitor, or both and the monitors have been certified in accordance with the requirements of part 75 of this chapter, part 60 of this chapter, or an applicable State continuous monitoring program. (F) The installed gas and/or stack gas volumetric flow rate monitors are required, by an applicable Federal or State regulation or the unit's operating permit, to undergo periodic quality assurance testing in accordance with appendix B to part 75 of this chapter, appendix F to part 60 of this chapter, or an applicable State continuous monitoring program. Subparagraph (b)(5)(ii)(D) is the sticking point. Using a CEMS is required if "[t]he unit has installed CEMS" but the paragraph does not say when the installation must have occurred, or even if there is such a baseline. Although the provision should be read to apply whenever a CEMS is installed, it is susceptible to a more limited misreading. Encouragingly, some provisions that reference this basic requirement suggest that it is intended to require GHG CEMS whenever a CEMS is required to be installed, as they tend to refer to the requirement in the present tense. Ethanol plants operators, for instance, are required to use CEMS for reporting "[i]f [they] operate and maintain a CEMS that measures total CO_2

consistent with the requirements in subpart C of this part." Ammonia facilities are likewise required to use CEMS if they "meet the conditions" set out in proposed 40 C.F.R. §98.33(b)(5)(ii). Such a requirement would make little sense if, without explicitly saying so, it excluded CEMS installed after 2010. EPA should take steps to clarify that it does not intend this odd result. Otherwise, it risks a situation where sources which are required to install some form of CEMS after 2010 insist that they need not report GHG emissions using the CEMS, solely because they have installed the equipment after the effective date. The best way to avoid this outcome, and the only way consistent with the rule's emphasis on using direct measurement whenever it is available, is to state firmly that the GHG CEMS requirement applies whenever a covered facility is required to install a CEMS to monitor any pollutant, and not only if a CEMS was in use prior to the effective date of the rule. EPA can best make this clarification by taking two steps: (1) Revise the Preamble to clarify references to CEMS which are "already" in use to state that GHG CEMS will be required whenever a covered source either is required to install a CEMS of any kind, or does so on its own volition and (2) Revise the rule's text to insert the words "at any time" in between "has" and "installed" in proposed 40 C.F.R. §98.33(b)(5)(ii)(D), and make any other necessary conforming changes.

Response: EPA has revised the rule to clarify that all six requirements must be met in order for Tier 4 to apply, but does not believe that any further language is necessary to clarify that Tier 4 will be required of any sources that meet all of the criteria in the future.

Commenter Name: Marc J. Meteyer
Commenter Affiliation: Compressed Gas Association (CGA)
Document Control Number: EPA-HQ-OAR-2008-0508-0981.1
Comment Excerpt Number: 17

Comment: The proposed rule refers to a section §98.33(a)(1)(iv)(D) while describing the data needs for employing CO_2 CEMS. There is no such §98.33(a)(1)(iv)(D). Perhaps the agency meant to reference §98.33(e)(3)(ii)(D)?

Response: EPA has corrected this error. The paragraph referenced in the comment (§98.33(a)(4)(i) in the final rule) now refers to §98.33(a)(4)(iv).

Commenter Name: Craig S. Campbell
Commenter Affiliation: Lafarge North America
Document Control Number: EPA-HQ-OAR-2008-0508-0674.1
Comment Excerpt Number: 13

Comment: If CO_2 CEMs are used, proposed 40 CFR §98.33(e)(2) requires calculation of % biogenic CO_2 emissions using equations C-12, C-13, C-14. The annual biogenic CO_2 mass emissions are then to be determined by multiplying the % biogenic by the total annual CO_2 mass emissions as measured by the CEMs. This calculation of annual biogenic CO_2 mass emissions does not take into account that a portion of the total annual CO_2 emissions measured by the CO_2 CEMs will be calcination emissions. Therefore the resultant calculation of annual biogenic CO_2

emissions will be incorrect. Lafarge recommends that EPA review and revise the calculation method provided in proposed 40 CFR §98.33(e)(2) to account for calcination emissions.

Response: EPA acknowledges the concerns, and its method now requires the subtraction of both fossil fuel combustion CO_2 emissions and process CO_2 emissions to calculate biogenic CO_2.

Commenter Name: Rhea Hale
Commenter Affiliation: American Forest & Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2008-0508-0909.1
Comment Excerpt Number: 12

Comment: Based on the following discussion, AF&PA requests that facilities be able to use the WRI/WBCSD GHG Calculation Tool, and default parameters recommended therein, for estimating methane emissions from industry landfills, rather than using the formulas and parameters in the EPA rule. NCASI has assembled data and completed several studies that improve estimates of methane emissions from pulp and paper mill landfills. These data and studies are summarized in the attached NCASI Special Report No. 08-05. Pages 13 and 14 of that report present descriptions of the methods used by NCASI (which are analogous to the IPCC methods used by EPA in the national inventory) to estimate methane emissions from pulp and paper mill landfills. [See DCN: EPA-HQ-OAR-2008-0508-0909.2 for attachment] The report indicates that, in 2005, the methane emissions from all forest products facility landfills in the U.S. were estimated to be 2.2 Tg CO_2 eq. per year. (See Table 2.10 in NCASI Special Report No. 08-05.) Although the report does not show the emissions for pulp and paper mills separate from wood products facilities, the pulp and paper mill portion of the 2.2 Tg CO_2 eq. per year was 1.2 Tg CO_2 eq. per year. NCASI Special Report No. 08-05 also estimated that total direct emissions due to fuel combustion at U.S. pulp and paper mills was 57.7 Tg CO_2 eq. in 2004. Accordingly, 1.2 Tg CO_2 eq from landfills comprise less than two percent of the industry's fuel combustion-related emissions. NCASI compared CH_4 emission estimates using methods in the WRI/WBCSD GHG Protocol GHG Calculation Tool, the "bulk waste" method recommended by the IPCC, and the method proposed by EPA in this rule for a hypothetical industry landfill receiving 20,000 dry tonnes of wastewater treatment plant residuals (30% solids) annually from 1950 through 1999. EPA's proposed default values for k and Lo were used in the calculations for illustrative purposes. The results were almost identical – all ranging within 15 tonnes of CH_4 (215 tonnes CO_2 eq.) in 1999 – with the WRI/WBCSD GHG Protocol GHG Calculation Tool methods yielding estimates approximately 0.33% higher than the other two methods. For consistency purposes, we recommend that the industry be allowed to continue to calculate these emissions using the WRI/WBCSD GHG Protocol GHG Calculation Tool. Two important differences do exist however between the WRI/WBCSD GHG Protocol GHG Calculation Tool and the method proposed by EPA. First, we believe that the default DOC weight fraction for pulp and paper (0.2, "wet basis") listed in proposed Table HH-1 is too high. WWTP residuals are the main organic-carbon containing material landfilled at pulp and paper industry landfills (NCASI 1999). NCASI has developed limited total organic carbon data for a number of industry WWTP residuals, and obtained values for WWTP residuals landfilled by different pulp and paper mills. These data are summarized below. [See DCN: EPA-HQ-OAR-2008-0508-0909.1 for table showing each "residual", its "solids fraction", "TOC fraction dry basis", and "TOC fraction wet basis"] The data presented in the table are distinct from but in close agreement with data published by Mabee and Roy (2003) indicating an average TOC fraction of 0.310 (dry basis) for six WWTP residuals. Considering that TOC may overstate DOC, and that WWTP residuals are commonly co-disposed with other materials containing little or no organic carbon (e.g., ash), it is clear that a DOC of 0.2 on a wet basis is too high. The default value for Lo in the WRI/WBCSD GHG Protocol GHG Calculation Tool is 100 m^3 CH_4/dry tonne. This is equivalent to a default DOC of about 0.2 tonnes CH_4/dry tonne of residuals or 0.06 tonnes CH_4/wet tonne assuming the residuals have 30% solids content. The proposed default value of 0.06/year for the methane generation rate constant, k, for pulp and paper mill landfills is also probably too high. To our knowledge no scientific investigation of k for pulp and paper mill landfills has ever been completed. However, anecdotal information suggests that the rate of gas generation at such landfills is usually lower than at municipal solid waste (MSW) landfills. EPA's default k for MSW landfills in AP-42 is 0.04/year. The default value in the WRI/WBCSD GHG Protocol GHG Calculation Tool is 0.03/year. As noted earlier, AF&PA suggests that the WRI/WBCSD GHG Protocol GHG Calculation Tool be allowed for use in calculating landfill methane emissions. This tool, including the default values for Lo and k, has been peer reviewed and its use is widespread within the industry. [Footnote: WRI and WBCSD organized the peer review process which included evaluation by experts from the pulp and paper industry, the American Petroleum Institute (API), and the Center for Energy Efficiency (CENEf) in Russia, in addition to detailed review by WRI and WBCSD staff.] The foregoing discussion supports use of the default values for Lo and k in the tool, but site-specific values should be allowed if they are known.

Response: In regard to industry landfills, Subpart HH, EPA is not going final with that source category at this time. Please see Section III. II. of the Preamble and the separate comment response document.

Commenter Name: Sarah B. King
Commenter Affiliation: DuPont Company
Document Control Number: EPA-HQ-OAR-2008-0508-0604.1
Comment Excerpt Number: 25

Comment: §98.33 – EPA has not provided a de minimis threshold below which the greenhouse gas emissions from a stationary combustion source do not need to be calculated by a facility and otherwise included in the greenhouse gas reporting program. EPA should add a de minimis threshold to avoid the necessity of reporting on dozens or even hundreds of minor units, such as comfort hot water heaters, gas furnaces for buildings, etc. It would be unnecessarily costly to add flow measurement devices to these units to facilitate calculation. DuPont recommends that EPA add a de minimis threshold in §98.31 or §98.32 to eliminate reporting of emissions from equipment whose emissions fall under the threshold. To emphasize our concern with this provision, we refer to our comments in Section II.G, above, recommending de minimis exclusions. We also note that a site-wide fuel accounting provision would be sufficient to assure that there is full GHG emissions accounting from stationary combustion units without reporting on all the individual minor sources.

Response: See the Preamble, Section II. K., and the response to comment EPA-HQ-OAR-2008-0508-0423.2 excerpt 40 for the response on de minimis reporting for small emission points.

While EPA does not agree that there should be a de minimis emissions exclusion, EPA has expanded the list of exempted source categories to include portable equipment, emergency generators, and flares (though flares may be covered in other subparts). EPA has also removed the cumulative 250 mmBtu/hr restriction on unit aggregation, and believes that the expanded availability of this option will reduce the reporting burden on facilities. Please also refer to §98.2(a)(1) – (3) for facility requirements.

Commenter Name: Renae Schmidt
Commenter Affiliation: CITGO Petroleum Corporation
Document Control Number: EPA-HQ-OAR-2008-0508-0726.1
Comment Excerpt Number: 10

Comment: The Tier 4 applicability triggers are confusing in the rule - see page 16634 of FR (but is clearly stated in the Preamble - see page 16483 of FR). EPA should make sure that the Tier 4 Calculation Methodology is properly applied per rule intent. CITGO recommends that EPA insert Table C-l from the Preamble into the body of the rule. This table is clear and unambiguous in determining when to apply the various combustion calculation tiers. Of particular note is section 40 CFR 98.33(b)(5)ii (A) and (C) Paragraph 40 CFR 98.33(b)(5)ii (A) reads: "The unit has a maximum rated heat input capacity greater than 250 mmBTUIhr, or if the unit combusts municipal solid waste and has a maximum rated input capacity greater than 250 tons per day of MSW." This paragraph should read: "The unit has a maximum rated heat input capacity greater than 250 mmBTUIhr of solid fuel, or if the unit combusts municipal solid waste and has a maximum rated input capacity greater than 250 tons per day of MSW." Similarly, paragraph 40 CFR 98.33(b)(5)ii (C) reads: "The unit has operated for more than 1,000 hours in any calendar year since 2005." This paragraph should read: "And the unit has operated for more than 1,000 hours in any calendar year since 2005."

Response: EPA acknowledges the commenter's concerns regarding Tier 4 applicability. EPA has revised the rule to clarify that all six criteria must be met before Tier 4 is required.

Commenter Name: Ron Downey
Commenter Affiliation: LWB Refractories
Document Control Number: EPA-HQ-OAR-2008-0508-0719.1
Comment Excerpt Number: 26

Comment: 40 C.F.R. 98.33 does not specify whether solid fuel calculations for coal should use throughputs for "dry" or "as received" fuel. 40 C.F.R. 98.33(a) should be revised to specify that all fuel calculations should use dry solid fuel throughputs for consistency and more accurate results.

Response: EPA believes that fuel high heating value calculations should be done on an as-received basis, and that no additional language is necessary in the rule to clarify this.

Commenter Name: Michael Garvin
Commenter Affiliation: Pharmaceutical Research and Manufacturers of America (PhRMA)
Document Control Number: EPA-HQ-OAR-2008-0508-0959.1
Comment Excerpt Number: 9

Comment: There will be significant difficulties in calculating and reporting GHG emissions from thermal oxidizer units (TOUs), liquid waste incinerators (LWIs), and other incinerators (e.g., pathological waste incinerators, medical/infectious waste incinerators and solid waste incinerators). Calculating emissions from supplemental fuel combustion is a very straightforward calculation; however, accounting for the carbon dioxide formation associated with the combustion of organic solid, liquid, and/or vapor effluents will be very difficult. We believe that every TOU/LWI/incinerator installation would be required to install a carbon dioxide CEM system, with the corresponding operational, maintenance, recordkeeping, and reporting requirements. This approach significantly increases the costs and resources required to comply with the proposed rule, which is intended to collect GHG emissions data that will be used to develop a future GHG regulatory scheme. In light of the costs and associated burdens associated with quantifying the GHG emissions associated with the combustion of organic solid, liquid, and/or vapor effluents, PhRMA respectfully requests that EPA not require GHG reporting for combustion sources which are in place for environmental protection (i.e., TOUs and LWIs) and smaller-scale solid waste incinerators (i.e., pathological, medical/infectious, and solid waste incinerators). To accomplish this, PhRMA proposes the following language for Section 98.33(a)(1): "For thermal oxidation units, liquid waste incinerators and smaller-scale solid incinerators (e.g., pathological, medical/infectious, and solid waste incinerators located at industrial facilities), GHG emissions are to be calculated based solely on supplemental fuel combustion." If this change is not made, emissions factors for the range of wastes that could be incinerated at industrial facilities must be provided.

Response: See the Preamble and source category Preamble section(s), as well as the separate comment response document(s), for the response on the definition of the source category, and the selection of the level of reporting.

EPA acknowledges the concerns of the commenter. A number of exemptions to GHG emissions reporting have been added for certain unconventional combustion processes and types of fuel. §98.30 of the final rule clarifies the definition of the general stationary fuel combustion source category and provides an expanded list of exemptions from GHG emissions reporting under Subpart C. Flares are excluded from Subpart C, but are addressed by means of special protocols in other subparts of the rule. Also hazardous waste incinerators only report the GHG emissions from combustion of supplementary fossil fuels listed in Table C-1. Other combustion units with heat input less than 250 mmBtu/hr are only required to report emissions from fuels in Table C-1. EPA believes that these provisions account for all appropriate allowances and require all appropriate calculations necessary to satisfy the intent of Part 98, to collect accurate and consistent GHG emissions data that can be used to inform future decisions.

Commenter Name: Gregory M. Adams
Commenter Affiliation: Sanitation Districts of Los Angeles County
Document Control Number: EPA-HQ-OAR-2008-0508-0710.1
Comment Excerpt Number: 8

Comment: Under §98.6, p. 16626: Standard conditions are defined in the proposed rule as 14.7 pounds per square inch and 60 degrees Fahrenheit. However, in Subpart C, §98.33 – General Stationary Fuel Combustion Sources, the Molar Volume (p. 16633) is listed as 849.5 scf per kg-mole at standard conditions. Our calculations suggest this value should be 836.5 scf per kg-mole. Please confirm that the molar volume listed is referenced to the standard temperature stated in 98.6, p. 16626.

Response: EPA has revised the definition of "Standard conditions or standard temperature and pressure (STP)" in §98.6 to mean "68 degrees Fahrenheit and 14.7 pounds per square inch absolute." Given this revised definition, EPA believes that the value for MVC provided in Equation C-5 is correct.

Commenter Name: H. Allen Faulkner
Commenter Affiliation: Ascend Performance Materials, LLC, Decatur Plant
Document Control Number: EPA-HQ-OAR-2008-0508-1578
Comment Excerpt Number: 3

Comment: Ascend operates two unique devices for the production of coke from coal at its Decatur Alabama Plant. To our knowledge these are the only two units like this in the United States. Our coking units burn the volatiles out of the coal and produce a high grade "buckwheat" coke used primarily in the steel industry. Generally, half the coal input to Image is discharged as coke and the other half is the volatiles combusted. Ascend is requesting allowances in the Tier 3 methodology to subtract the carbon remaining in the coke product from the carbon in the coal input. The coking units partially combust coal to make a product (i.e. coke). These coking units are designed for incomplete combustion. Much of the carbon will remain in the coke product and not be converted to CO_2 in the off-gas. Therefore, we suggest provisions in the Tier 3 methodology for product sampling for carbon and subtract the carbon remaining in the coke from the carbon in the coal prior to calculating the CO_2 emissions.

Response: EPA refers the commenter to §98.2(a)(1) of Subpart A that requires the annual GHG report must cover all source categories and GHGs for which Calculation Methodologies are provided in Subparts C through JJ of this part. See also the response to comment EPA-HQ-OAR-2008-0508-1578 excerpt 2 for additional rationale relating to coverage of coke under the rule.

EPA has revised the use of Tier 3 in §98.33(b)(3) of Subpart C to be required only when a unit with a maximum rated heat input capacity greater than 250 mmBtu/hr that combusts any type of fuel listed in Table C-1 of this subpart (except MSW), unless the use of Tier 1 or 2 is permitted or Tier 4 is required. Tier 3 is also required for a unit with a maximum rated heat input capacity greater than 250 mmBtu/hr that combusts a fuel that is not listed in Table C-1 of this subpart, provided that the use of Tier 4 is not required, and the fuels provide ten percent or more of the annual heat input to the unit or to a group of units served by common supply pipe, as described in §98.36(c)(3).

Commenter Name: Melvin E. Keener
Commenter Affiliation: Coalition for Responsible Waste Incineration (CRWI)
Document Control Number: EPA-HQ-OAR-2008-0508-0446.1
Comment Excerpt Number: 3

Comment: Subpart sources are also required to report methane, and nitrous oxide emissions. Emission factors for these two gases are shown in Table C-3 for common fuels and certain wastes. If the materials burned in a facility are not included in this Table, it is not clear how to report these emissions. EPA stated in the Technical Support Document for this proposed rule that methane and nitrous oxide accounts for less than one percent of the carbon dioxide equivalents. Since greater than 99% of the greenhouse gas emissions for this sector are covered by reporting carbon dioxide, little additional accuracy would be gained by reporting methane and nitrous oxide emissions. CRWI suggests that only facilities that have default emissions factors in Table C-3 be required to report methane and nitrous oxide emissions. All incinerators, boilers, and process heater that burn hazardous waste are required to destroy 99.99% of the organic material fed. Some of these materials are very difficult to destroy. Since methane is very easy to destroy, it is highly unlikely that any methane will be emitted from these facilities. This is not a compound 'that many hazardous waste combustors routinely measure. The One CRWI member that measured methane emissions found that the concentration was less than 1 ppmv in the stack. Given this information, CRWI sees no reason why these facilities should be required to report methane emissions. Most, if not all will simply report zero emissions of methane. There is very little, if any, information on nitrous oxide emissions for hazardous waste combustors. As far as we know, this has never been measured during testing. However, there is information in the literature that indicates the nitrous oxide emissions from high temperature combustion are very small. The Department of Energy stated on their web site that "Until a few years ago, fuel combustion was thought to be a major source of nitrous oxide emissions. However, the discovery of a sampling error, which resulted in erroneously high emissions factors, revealed that combustion is actually a minor anthropogenic source." http://www.eia.doe.gov/oiaf/1605/archive/87-92rpt/chap4.htnil — accessed 4/20/09 This is echoed in the technical support document3 for this proposed rule where EPA states In addition,- the 2009 inventory of greenhouse gas-emissions in the United States, EPA estimated that the 2007 nitrous oxide emissions from waste combustion were 0.4 Tg CO_2 equivalents. The total U.S. greenhouse gas emissions for 2007 were 7,150.1 Tg CO_2 equivalents. Nitrous oxide emissions from this source category represent less than 0.006 percent of the total greenhouse gas emissions. Research on nitrous, oxide formation or destruction during the combustion processes gives the same picture. In a 1989 paper, Miller and Bowman stated that "N_2O is a very short-lived species in hot combustion gases..." (page 324). Miller, J.A., and C.T. Bowman. 1989. Mechanism and Modeling of Nitrogen. Chemistry in Combustion. Prog. Energy Combust. Sci., Vol. 15: 287 - 338. In a subsequent article, Miller and Bowman state that "At low temperatures, the N_2O is relatively stable and appears as a major product in the gas stream; however, at temperatures above 1150 k, the calculations show that N_2O decays rapidly in the gas stream and is still decomposing at the exit of the reactor..." [Footnote: Miller, J.A., and C.T. Bowman. 1991. Kinetic Modeling of the Reduction of Nitric Oxide in Combustion Products by Isocyanic Acid. International Journal of Chemical Kinetics, Vol. 23: 289.] The temperature mentioned in the quote corresponds to approximately 1600° F, lower than the temperatures in hazardous waste combustors. In addition, the authors state that nitrous oxide decays rapidly in gas-phase temperatures above 1150 K (page 310). Finally, in his book, Kuo' states that N_2O formed during combustion reacts rapidly with hydrogen ions to form [Footnote: Kuo, K.K. 2005. Principles of Combustion, John Wiley & Sons, Inc.] (p. 268). Given this, it seems logical to require only the hazardous waste combustors that; have emission factors in Table C-3 to report their emissions for methane and nitrous oxide. This would not create a large error in reporting since all of the sources in this category are less than one percent of the CO_2e. Not reporting emissions for those sources without emission factors would be much less than one percent. This is a similar conclusion to what EPA came to in the Preamble (74 Fed. Reg. at 16485) when discussing, whether to require the development of site-specific emission factors for methane and nitrous oxide. Here, EPA decided that this would be "too costly for the small improvement in data quality it might achieve." Based on the science of nitrous oxide formation and destruction, CRWI suggests that EPA require reporting of nitrous oxide emissions only for those facilities that can use the emission factors found in Table C-3. Since this is such a-small portion of the CO_2e, the gain in accuracy would not be worth the cost.

Response: EPA acknowledges the concerns of the commenter. Section 98.33(c) of the final rule excludes from calculations any CH_4 and N_2O emissions from fuels that are only used for unit startup or are not listed in Table C-2 (formerly C-3). Table C-2 has been revised to include CH_4 and N_2O emission factors for more fuels, including blast furnace gas and coke oven gas, as well as generic emission factors covering all fuel types listed in Tables C-1. EPA has also dropped the option which allowed facilities burning other fuels to develop site-specific emission factors based on the results of source testing. Finally, hazardous waste incinerators and all units with a rated heat input capacity less than 250 mmBtu/hr are only required to report GHG emissions from the combustion of any fuels listed in Table C-1.

Commenter Name: Melvin E. Keener
Commenter Affiliation: Coalition for Responsible Waste Incineration (CRWI)
Document Control Number: EPA-HQ-OAR-2008-0508-0446.1
Comment Excerpt Number: 2

Comment: CRWI suggests that EPA develop a mechanism by which additional emission factors can be added to Tables C-1 and C-2. As facilities get more experience in developing and using site-specific emissions factors, there may be a need to expand these tables.

Response: Based on comments, additional factors have been added to Tables C-1 and C-2 (formerly C-3), and other factors may be brought into future programs.

Commenter Name: Melvin E. Keener
Commenter Affiliation: Coalition for Responsible Waste Incineration (CRWI)
Document Control Number: EPA-HQ-OAR-2008-0508-0446.1
Comment Excerpt Number: 1

Comment: Hazardous waste combustors will not be able to use either Tier 1 of Tier 2 because there are no default values for their "fuel" in Tables C-1 and C-2. Thus, it appears that these units will, be forced to use either Tier 3 or 4 to calculate their carbon dioxide emissions. Very few of these units have carbon dioxide continuous emission monitors so most will be forced to use Tier 3. If every-facility that does not have a carbon dioxide monitor tried to purchase and install one in the fourth quarter of 2009, it is highly unlikely there would be enough monitors available to fill the need. While this may be appropriate for certain conditions, it will not be appropriate in others. Some hazardous waste combustion facilities will burn thousands of different waste streams in a year. Some are burned daily; others are burned once or twice a year Trying to put a system in place to use Tier 3 would quickly become an unmanageable problem. Thus, certain hazardous waste combustors have no good choices on how to estimate, their carbon dioxide emissions. To address this problem, CRWI has three suggestions. The first one is to require reporting only from those facilities that have a default emissions factor in either Tables C-1 or C-2. This would cover the major combustion sources while not subjecting the minor sources to extensive testing requirements. The/rest of the sources contribute relatively small amounts to the total inventory. EPA has already recognized the relatively small contribution by exempting hazardous waste from the calculations and reporting in the landfill subpart of this proposed rule. The second suggestion is to add a Tier 5 to Subpart C so those facilities, if they choose to do so, can develop site-specific emissions factors. This is already allowed (or required) on some level for the cement kiln (98.83) and nitric acid production (98.223) categories. Hazardous waste combustors conduct, performance tests every 5 years as required under Part 63,'Subpart EEE. During these periodic tests, the facility could measure and analyze for the parameters necessary to develop a site-specific emissions factor. Other sources may be able to, use historical data to develop a relationship between carbon dioxide emitted and mass of waste burned. Adding the ability to develop a site-specific emission factor, gives these facilities another tool to accurately estimate carbon dioxide emissions without the unnecessary burden of frequent sampling or continuous monitoring. The third suggestion is to allow facilities to use Dulong's approximation to estimate the carbon content, of the materials combusted. C. R. Brunner, 1993. Hazardous Waste Incineration, Second Edition, McGraw-Hill, Inc., p. 326. Normally, this approximation is used to estimate the Btu's per pound of a material based on carbon, hydrogen, oxygen, and sulfur content of the material to be burned. Some hazardous waste combustors will have a good estimate of the sulfur content and the Btu/lb but will not have a good estimate of the carbon content. By rearranging this equation, assuming the oxygen content of the waste is small, and that there are two hydrogens for every carbon, the equation can be used to estimate the carbon content for materials burned.

Response: In the revised §98.30(c), unless CEMS are used to quantify CO_2 mass emissions, hazardous waste incinerators are only required to report GHG emissions from the combustion of any supplemental fuels listed in Table C-1.

Commenter Name: Ron Downey
Commenter Affiliation: LWB Refractories
Document Control Number: EPA-HQ-OAR-2008-0508-0719.1
Comment Excerpt Number: 27

Comment: The formulae set forth in 40 CFR 98.33(a)(2)(iii) and 98.33(c) regarding the methods for calculating emissions from the combustion of municipal solid waste ("MSW") does not apply to lime plants. The formulae assume MSW is used to produce steam, but lime plants do not produce steam from burning MSW. LWB proposes the following formulae to calculate emissions from "non-steam" facilities: Eq. C-2b would be $CO_2 = 1 \times 10^{-3} * (EF) * (Fuel)_p * (HHV)_p$. Eq. C-10b would be CH_4 or $N_2O = 1 \times 10^{-3} * (EF) * (Fuel)_p * (HHV)_p$. $(Fuel)_p$ and $(HHV)_p$ would use the same definition as Eq. C-2a and C-1 0a.

Response: EPA has added default CO_2 emission and heat content factors for municipal solid waste that may be used in conjunction with the Tier 1 methodology if the unit does not produce steam.

Commenter Name: See Table 10
Commenter Affiliation:
Document Control Number: EPA-HQ-OAR-2008-0508-0635
Comment Excerpt Number: 18

Comment: It is not clear from the rule's text whether the reporting rule itself (as opposed to some other federal requirement) may ever independently require sources to install a CEMS – indeed, both the text and EPA's statements in the Preamble suggest the contrary. EPA should instead make clear that such a requirement is present. The ambiguity lies primarily in proposed 40 C.F.R. §98.33(b)(5)(ii). Looking again at the list of factors in that provision, listed above, note that it is not clear whether the list is conjunctive or disjunctive. In other words, must a source directly monitor its emissions only if it satisfies every factor in the list, or is satisfying one factor in the list sufficient to require GHG CEMS? The list itself provides little guidance. The first four factors could easily be disjunctive: A) The unit has a maximum rated heat input capacity greater than 250 mmBtu/hr, or if the unit combusts municipal solid waste and has a maximum rated input capacity greater than 250 tons per day of MSW. (B) The unit combusts solid fossil fuel or MSW, either as a primary or secondary fuel. (C) The unit has operated for more than 1,000 hours in any calendar year since 2005. (D) The unit has installed CEMS that are required either by an applicable Federal or State regulation or the unit's operating permit. Indeed, it would be entirely appropriate if they were disjunctive, as burning municipal solid waste, burning solid fossil fuel, operating for long periods, or having a CEMS of any kind would all be sensible reasons to require direct monitoring of GHG emissions. As we have outlined above, it is precisely these sort of factors – and, in particular, burning solid fuels – which EPA itself has recommended should trigger a CEMS requirement. The last two factors, however, cut a bit differently. Paragraphs (E) and (F) both refer to particular certification and quality control requirements for a CEMS. They do not make sense independently of paragraph (D), as a CEMS cannot be certified or assessed unless it exists in the first place. So those factors, at least, must be conjunctive. The factor list, in short, is confusing. Portions of it could, and should, independently trigger CEMS, while other sections presume CEMS has already been installed.

EPA appears at present to be working under the latter presumption. The Preamble states that this provision "would require the use of certified CEMS to quantify CO_2 mass emissions where existing CEMS equipment is installed." This line suggests that, whatever other factors on the (b)(5)(ii) list are satisfied, subparagraph (b)(5)(ii)(D), which specifies that a CEMS has already been installed, must be fulfilled. EPA complicates this impression, however, by writing, a few lines later, that "the use of CEMS . . . is required for solid fossil fuel-fired units with a maximum heat capacity greater than 250 mmBtu/hr (and for units with a capacity to combust greater than 250 tons per day of [municipal solid waste]." These requirements, which are factors (b)(5)(ii)(A)-(B), phrased slightly differently, appear to stand alone, suggesting that these fuels trigger a CEMS requirement, even if a CEMS has not been installed. Nonetheless, in the next paragraph, EPA writes "[i]n addition [to the above-listed factors], in order to be subject to the [direct monitoring] requirements," the 1,000 hour operation factor, (b)(5)(ii)(C), must be satisfied. This language, of course, suggests the factors must all be satisfied. On balance, and after reviewing EPA's guidance documents for this rule, which so indicate, we take this conjunctive reading to be the one EPA intends. If so, EPA should rethink this approach (and, if not, EPA should make that clear). First, the conjunctive reading will cause some practical difficulties because not all of the factors operate in the same way. Unlike factors (b)(5)(ii)(A) - (D), each of which could stand alone, factors (b)(5)(ii)(E) - (F) are really just CEMS operations requirements. Certainly, they should be met by plants using CEMS to measure GHGs, but it makes little sense to recast them as requirements for employing CEMS at all. They specify how well CEMS should perform, not the characteristics of a source that should use CEMS in the first place. Leaving them as independent factors would mean that a source with a poorly-performing CEMS would be excused from direct monitoring all together, because it would not satisfy subparagraphs (b)(5)(ii)(E) - (F). That result gets the proper incentives backwards: Sources should be encouraged to properly certify and maintain their CEMS, not be rewarded with less rigorous monitoring if they let matters slide. Treating these 'maintenance-based' concerns as requirements for sources using CEMS, rather than as factors triggering CEMS would avoid that improper result. If a source has a CEMS device, it should upgrade and use it. Thus, each of factors subparagraphs (b)(5)(ii)(A) - (D) should be disjunctive. That reading is consistent with the course EPA takes in the Acid Rain Program and with good practice. Finally, whether or not EPA makes these modifications, it should clarify the language other provisions of the rule use to reference the CEMS factors, as it is presently inconsistent. Some of the references address each factor: Ammonia manufacturers, for instance, are required to use a GHG CEMS if they "meet the conditions specified in . . . §98.33(b)(5)(ii)(A) through (F),"120 and cement kiln operators are similarly required to directly monitor their emissions if they "meet the conditions specified in §98.33(b)(5)(ii)."[121] Other provisions are less clear, seeming to overlook some, but not all, of the requirements of proposed §98.33(b)(5)(ii): Ferroalloy, iron and steel, and lead producers, for instance, are all required to "estimate emissions according to the requirements in §98.33" if they "operate and maintain a CEMS that measures CO_2 consistent with the requirements in subpart C [which contains §98.33(b)(5)(ii)]."[122] This language calls subparagraphs (b)(5)(ii)(D) - (F) to mind, as they specify requirements for which a "CEMS that measures CO_2," should be 'consistent with,' but leave readers guessing as to whether (if ever) subparagraphs (b)(5)(ii)(A) - (C) might matter. EPA should clearly state which factors are meant to apply in each case and should either use the same factor list in each circumstance or give clear reasons why it does not.

Response: EPA acknowledges the commenter's concerns regarding Tier 4 applicability. EPA has revised the rule to clarify that all six criteria must be met before Tier 4 is required.

Commenter Name: Lorraine Krupa Gershman
Commenter Affiliation: American Chemistry Council (ACC)
Document Control Number: EPA-HQ-OAR-2008-0508-0423.2
Comment Excerpt Number: 77

Comment: In Table C-1 of Subpart C, under the heading of "Petroleum Products" there is a listing for "Natural Gasoline" with a default HHV of 0.110. It would at first appear that "natural gas" is intended, but that fuel appears elsewhere in Table C-1. "Motor gasoline" also appears under this heading in Table C-1, but neither that term nor "natural gasoline" is defined in §98.6 and neither appears in Table C-3 of Subpart C, where the term "gasoline" does appear. "Gasoline" is not defined in §98.6. ACC suggests that EPA add definitions of "gasoline," "natural gasoline" and "motor gasoline" to §98.6. The headings "Biomass-derived Fuels (solid)" and "Biomass-derived Fuels (Gas) appear in Table C-1. Listed under the heading "Biomass-derived Fuels (solid)" is the phrase "Wood and Wood waste (12% moisture content) or other solid biomass-derived fuels." Table C-3 contains the terms "Other Biomass" and "Wood and Wood Waste," without a moisture content qualifier, but that table does not include a gaseous biomass-derived fuel entry. EPA should clarify its intent when using the "Biomass" terms.

Response: In response to the comments received, EPA has greatly expanded §98.6 to include detailed explanations of the meanings of all terms used in 40 CFR Part 98 that required clarification. The final rule includes all additional and revised language deemed necessary.

In response to the comment, EPA has significantly revised Tables C-1 and C-3 (now C-2) to clarify what emissions from biomass-derived fuels are reported. Any fuel types not listed with default factors are exempted from reporting CH_4 or N_2O emissions.

Commenter Name: Lorraine Krupa Gershman
Commenter Affiliation: American Chemistry Council (ACC)
Document Control Number: EPA-HQ-OAR-2008-0508-0423.2
Comment Excerpt Number: 76

Comment: In Table C- 1 of Subpart C, under the heading of "Petroleum Products" there is a listing for "LPG (energy use)". There is no definition of "LPG" in §98.6. However, there is a definition of "liquefied natural gas (LNG)" in §98.6, but that fuel is not listed in any of the Tables in Subpart C. In Table C- 1 of Subpart C, under the heading of "Petroleum Products" there are listings for "Aviation gasoline" and "Jet fuel". These terms also appear in Table C-3. Neither of these terms is defined in §98.6. However, "Kerosene-type jet fuel" is defined in §98.6, but that term is not used in Subpart C. EPA should clarify its use of these three terms in the proposed rules.

Response: In response to the comments received, EPA has greatly expanded §98.6 to include detailed explanations of the meanings of all terms used in 40 CFR Part 98 that required clarification. The final rule includes all additional and revised language deemed necessary.

Commenter Name: Kim Dang
Commenter Affiliation: Kinder Morgan Energy Partners, L.P.
Document Control Number: EPA-HQ-OAR-2008-0508-0370.1
Comment Excerpt Number: 38

Comment: Kinder Morgan recommends the addition of the following to §98.6: Natural gasoline means a mixture consisting mostly of pentanes and heavier hydrocarbons, extracted from natural gas, that meets vapor pressure, end-point, and other specifications for natural gasoline set by the Gas Processors Association.

Response: EPA provides a definition of natural gasoline in §98.6 that is largely consistent with the recommendation by the commenter.

Commenter Name: See Table 6
Commenter Affiliation:
Document Control Number: EPA-HQ-OAR-2008-0508-0679.1
Comment Excerpt Number: 66

Comment: Continuous Emissions Monitoring System §98.6 (p. 16618): EPA's definition of CEMS includes a requirement for "readings every 15 minutes" which is not appropriate for a definition.

Response: See the Preamble and separate comment response document volumes for the response on the general monitoring approach and general recordkeeping requirements.

The commenter does not claim that the frequency of readings by equipment qualifying as a CEMS should be different than at least once every 15 minutes, but rather claims that a requirement for readings every 15 minutes is "not appropriate" to include in a definition. EPA does not agree with this comment because it is certainly reasonable to include, in the definition of a term (CEMS) that, on its face, includes the concept of "continuous" monitoring, a performance specification concerning frequency of monitored readings. Moreover, this performance specification has been used in defining "CEMS" in the Acid Rain Program since the program began in 1995 and, in conjunction with other elements of the monitoring requirements in that program, has resulted in a high level of data quality and consistency.

Commenter Name: Steven J. Rowlan
Commenter Affiliation: Nucor Corporation (Nucor)
Document Control Number: EPA-HQ-OAR-2008-0508-0605.1
Comment Excerpt Number: 43

Comment: In 98.33(b)(6), a new (iii) is needed stating when a source that newly acquires a CEMS after January 1, 2011 should begin reporting using Tier 4 calculation methodology.

Response: EPA disagrees with the commenter that a new section is required to deal with changes that occur after the passage of the rule. EPA does not believe that any further language is necessary to clarify that Tier 4 will be required of any sources that meet all of the criteria in §98.33(b)(4)(ii) or (iii) in the future.

Commenter Name: Steven J. Rowlan
Commenter Affiliation: Nucor Corporation (Nucor)
Document Control Number: EPA-HQ-OAR-2008-0508-0605.1
Comment Excerpt Number: 44

Comment: 98.33(c)(3) should include a cross-reference to the GWP Table A-1.

Response: EPA appreciates the comment but does not feel that a rule revision is necessary because the GWP Table A-1 applies to all Subparts.

Commenter Name: Jennifer McGraw
Commenter Affiliation: Center for Neighborhood Technology (CNT)
Document Control Number: EPA-HQ-OAR-2008-0508-0723.1
Comment Excerpt Number: 8

Comment: CNT encourages EPA to harmonize its default emissions factors, heating values, and any other default values supplied for reporting with default factors it uses in other materials. For example, the default high heat value for natural gas is 1,027 BTU/SCF in table C-1 of Subpart C of the Draft Reporting Rule; this value matches the default value in Table A-251 of EPA's Inventory of U.S. Greenhouse Gas Emissions And Sinks: 1990 – 2007; but the default value for anthracite is listed as 25.09 mmBTU/short ton in the first document and 22.573 million BTU/short ton in the second document. There may be some very logical reason for such variations, but if it just a matter of different source data we recommend choosing a standard default so as to avoid confusion among those using these documents as the basis of greenhouse gas estimates and analysis. We would further encourage EPA to work to harmonize and update such default values with other agencies such as the Department of Energy's Energy Information Agency.

Response: EPA has extensively reviewed the default emission factors and high heat values provided in Subpart C of the final rule, and believes that they are appropriate and, to the extent possible, consistent with those used in other programs.

6. MONITORING AND QA/QC REQUIREMENTS

Commenter Name: Keith Adams
Commenter Affiliation: Air Products and Chemicals, Inc.
Document Control Number: EPA-HQ-OAR-2008-0508-1142.1
Comment Excerpt Number: 25

Comment: The proposed rule requires periodic sampling and analysis of fuels for HHV or carbon content under §98.34(c)(1) and (2) and §98.34(d)(3). The rule implies this sampling and analysis is to be done by the consumer of the fuel, the reporting source. The proposed rule further describes minimum sampling and analysis frequencies for each fuel type. The proposed rule implies a need for characterization of standard commercial fuels to meet calculation method Tier 2 and 3, when, in actuality, the HHV and carbon content of standard fuels are nearly constant values and default values (e.g. Tier 1 calculation method) yield sufficiently accurate emission estimates. Recognizing the objective of the reporting rule is to develop a reasonable estimate of the annual emissions from a source: 1. Standard fuels of commerce (natural gas, LP gas, fuel oils, etc.) that are supplied to multiple consumers are more efficiently characterized by their suppliers than by their consumers. 2. Standard fuels of commerce (excepting coal) have very consistent H HV and carbon contents, requiring much lower characterization frequency. Monthly characterization, as required under §98.34(c)(1) and §98.34(d)(3), of such consistent fuels is costly and does not materially improve the annual estimate of emissions. 3. Process-specific fuel sources (e.g. refinery gas) vary over time, but requiring daily sampling and analysis is very burdensome and costly for a degree of characterization that is intended to yield an annual emission estimate. Air Products Comment: The characterization of standard fuels of commerce should not be required since default values employed under the Tier 1 calculation method will yield a sufficiently accurate emission estimate. If a fuel characterization is required, the characterization sampling and analysis should be the responsibility of the fuel supplier. Such suppliers should then be required to provide the characterizations to any fuel consumers, upon request. The agency should then accept these characterizations for use under Tier 2 and 3 calculation methods. The characterization frequency of standard fuels of commerce should be reduced to annually. The characterization of process-specific fuels should be reduced to monthly. Alternately, a source should be able to demonstrate that, after a period of required characterization, the variability of the average fuel characteristic (HHV or carbon content) is sufficiently small to justify a reduction in the sampling and analysis burden.

Response: See the Preamble and separate comment response document volume for the response on Method for Calculating GHG Emissions.

EPA appreciates the comment and has significantly revised the sampling requirements in the final rule. Sections 98.34(c) and 98.34(d) have been revised as follows: mandatory monthly fuel sampling and analysis requirements for traditional fossil fuels have been dropped from Tiers 2 and 3, and natural gas must be sampled only semiannually. For fuel oil and coal, a representative sampling is required for each fuel lot, i.e., for each shipment or delivery. For other liquid fuels and biogas, quarterly sampling is required. For other solid fuels, excluding municipal solid waste, weekly composite sampling with monthly analysis is required. For other gaseous fuels, the daily sampling requirement has been retained, but only for facilities with existing equipment in place that is capable of providing the data. Otherwise, weekly sampling is required, which may be postponed in favor of monthly sampling until 2011 if new equipment must be purchased or if existing equipment must be upgraded to meet the weekly sampling and analysis requirements.

The final rule clarifies that fuel sampling and analysis data provided by the supplier may be used in the emission calculations, and that fuel billing meters may be used to quantify fuel consumption. To simplify the emission calculations in Tiers 2 and 3, averaging of HHV and carbon content data is permitted if these data are obtained at least at the minimum frequency specified in §98.34. If the results of fuel sampling are received monthly or more frequently, the weighted annual average high heat value shall be calculated using Equation C-2b. If the results of fuel sampling are received less frequently than monthly, then the annual average HHV shall be calculated using the arithmetic average HHV for all valid samples for the year. However, regardless of the sampling frequency, the owner or operator must use the results of all available valid fuel analyses in the emissions calculations.

Under Subpart NN, EPA is providing the option for natural gas suppliers to report measured HHV and carbon content but it is not required.

Commenter Name: Alexander D. Menotti
Commenter Affiliation: Kelley Drye & Warren et. al LLP on behalf of the Steel Manufacturers Association (SMA) and Specialty Steel Industry of North America (SSINA)
Document Control Number: EPA-HQ-OAR-2008-0508-0656.1
Comment Excerpt Number: 8

Comment: Many steel facilities have natural gas burners above the 250 MMBTU threshold and therefore would be subject to the proposed Tier III reporting thresholds, which would require monthly sampling of the carbon content of natural gas. We do not believe that monthly sampling of pipeline quality natural gas is warranted. Such a requirement is inconsistent with methods EPA previously has found acceptable under Title IV. The Title IV requirements allow CO_2 calculations based on fuel flow measurements and heat content values supplied by natural gas utilities. If EPA believes that this is not sufficient to extrapolate a reasonable value for average carbon content, they should require that natural gas suppliers sample their product and provide the data to customers along with heating values. It is unreasonable to require each consumer to sample the same fungible commodity material.

Response: See the Preamble and separate comment response document volume for the response on methods for calculating GHG emissions.

EPA has revised §98.34 to require that natural gas be sampled semiannually. In addition, the final rule clarifies that fuel sampling and analysis data provided by the supplier may be used in the emission calculations, and that fuel billing meters may be used to quantify fuel consumption.

Commenter Name: Paul L. Carpinone
Commenter Affiliation: Tampa Electric Company (TECO)
Document Control Number: EPA-HQ-OAR-2008-0508-0717.1
Comment Excerpt Number: 9

Comment: Due to the potential variability of sulfur in coal, the need for stringent monitoring and emissions calculation is warranted, but variation in the carbon content of coal is much less. Because of the homogenous carbon content of coal, Tampa Electric recommends allowing a solid fuel-fired combustion source CO_2 emissions based on carbon content measurements and the amount of coal burned, so long as a facility can certify its coal quantity measurements.

Response: See the response to comment EPA-HQ-OAR-2008-0508-0455.1 excerpt 7 and the response to comment EPA-HQ-OAR-2008-0508-0580 excerpt 10 for EPA's rationale and approach to the use of CEMS.

The Tier 4 CEMS requirement is limited to larger solid fossil fuel units with an existing pollutant CEMS or volumetric flow rate monitor. EPA is requiring the use of CEMS due to the complexity of monitoring solid fuel consumption and the heterogeneous nature of the solid fuels. Many of these fossil-fuel fired units with a pollutant CEMS have an existing diluent monitor (O_2 or CO_2) that can be used to determine CO_2 emissions. EPA has permitted the use of carbon content measurements under Tier 3 requirements for solid fuels, if the unit is not required to meet Tier 4.

EPA is requiring the use of CEMS for solid fossil fuel-fired units due to the complexity of monitoring solid fuel consumption and the heterogeneous nature of the solid fuels. EPA has considered the commenter's analysis, but disagrees with the commenter's assessment of the burden associated with installing and maintaining the concentration and volume monitors that the rule requires be added to an existing CEMS. In the revised rule, EPA has clarified that if the unit in question meets all six criteria for Tier 4 to apply. EPA's estimates of monitoring costs are averages for a representative facility and may not represent the actual cost in individual circumstances. Note that EPA's cost estimates are annualized and do not widely differ from the capital cost cited in this comment. Further detail on the engineering cost analysis for Subpart C can be found in RIA (EPA-HQ-OAR-2008-0318-002) Section 4.3.

Commenter Name: Paul L. Carpinone
Commenter Affiliation: Tampa Electric Company (TECO)
Document Control Number: EPA-HQ-OAR-2008-0508-0717.1
Comment Excerpt Number: 10

Comment: Under proposed §98.43, Electric Generating Units (EGUs) subject to the requirements of the Acid Rain Program would continue to monitor and report CO_2 mass emissions in accordance with the monitoring requirements of 40 C.F.R. Part 75. As stated earlier, Tampa Electric supports the monitoring and reporting of this proposed rule to build on the already well establish ARP, but with some exceptions. There is a known upward bias in current stack flow measurement regulations under 40 C.F.R. Part 75. Under these measurement standards, a "reference monitor" is introduced each year and compared to an affected unit's stack flow monitor. A side-by-side comparison is performed, and for any resulting difference, a bias adjustment factor must be applied. The current rules, however, prescribe that only a positive adjustment factor can be applied. If the reference monitor demonstrates a higher level of flow than the affected unit's monitor, then a bias adjustment factor is added into the stack flow equation. If the reference monitor demonstrates a lower level of flow, no bias adjustment can be made. As a result, this procedure commonly results in high biased stack flow measurements. In the aggregate, Tampa Electric has noticed a bias adjustment for stack gas flow calculations (0 - 3% is typical with 3D probe technology) and the natural drift error associated with CEMS (± 3%), combining to establish an allowable upward error or uncertainty of up to 6%. This error represents a very costly misrepresentation of Tampa Electric's true GHG emissions. For example, at a carbon allowance value of just twelve dollars, Tampa Electric would end up paying an additional $10,800,000.00 annually for emissions never emitted. As a regulated utility, Tampa Electric expects that the costs to comply with new environmental regulations would be eligible for retail rate cost recovery through the Environmental Cost Recovery Clause. If approved as prudent by the Florida Public Service Commission, the costs required to comply with CO_2 emissions reductions would be reflected in retail customers' bills through this mechanism. Therefore, Tampa Electric recommends EPA should amend the stack flow measurement regulations under 40 CFR Part 75 to allow an adjustment to be made for a low or high bias of the CEMS instrumentation monitoring and reporting.

Response: See the Preamble, Section III. C., the Subpart D comment response document volume, and the response to comment EPA-HQ-OAR-2008-0508-0956.1 excerpt 20 for the rationale for using substitute data reported under Part 75.

Under this rulemaking, EPA is not revising Part 75 reporting requirements. EPA is keeping GHG monitoring requirements consistent with current monitoring because the Agency does not want to require two sets of data, as that would add to the cost and complexity of this rule. EPA has adopted changes to Part 75 over time to address these types of technical issues, including adoption of alternative stack flow reference test methods to address concerns with high bias.

Commenter Name: Keith A. Nagel
Commenter Affiliation: ArcelorMittal USA and Severstal North America
Document Control Number: EPA-HQ-OAR-2008-0508-0496.1
Comment Excerpt Number: 11

Comment: Another significant challenge is how to measure the amount of coke oven gas and blast furnace gas generated during steelmaking and thus ultimately combusted. Section 98.34(d)(1) proposes to require the tracking of gas combustion using flow meters. It would require that those flow meters be calibrated "prior to the first year for which GHG emissions are reported . . . using an applicable flow meter test method" and recalibrated annually or as recommended by the manufacturer. While that may be appropriate for assessing natural gas flow, there are significant practical problems with applying this approach where coke oven gas and blast furnace gas are involved. For example, the potential requirement to examine and/or calibrate orifice plates under the published standards is unworkable. The gas lines at issue do not have engineering bypasses and serve continuous processes that cannot be shut down without major operating implications for the entire facility (e.g., blast furnaces and coke ovens). We expect additional difficulty calibrating flow meters for coke oven gas under ASME standards at several of our facilities due to precipitate in the gas and the need for significant process interruptions. Finally, it would be exceptionally difficult to precisely measure the volume of blast furnace gas because it is widely distributed, contains potentially significant amounts of moisture and is conveyed in very large pipes. Those factors would make the use of ANSI requirements problematic and significantly impair the accuracy of flow meters. The rule should be amended to provide owners and operators the flexibility to quantify coke oven gas and blast furnace gas generation at the source using industry benchmarks. Rather than attempting to upgrade, calibrate and maintain countless meters plant-wide (with varying degrees of resulting accuracy), sources should be allowed to calculate the quantity of blast furnace gas using process information that will provide equal or greater precision. ArcelorMittal's Indiana Harbor facility uses just such a system, which involves measuring: (1) the total amount of nitrogen entering its blast furnaces (primarily in air) and (2) the total amount of nitrogen present in top gas coming from its blast furnaces. These measurements are highly accurate (due to the use of a frequently calibrated gas chromatograph). Since functionally all of the nitrogen introduced into the furnace leaves in resulting blast furnace gas, measuring nitrogen concentrations as a "tracer element" in top gas samples allows the plant to precisely determine the amount of blast furnace gas generated. This alternate approach would yield results that are significantly more reliable than the proposed metering – particularly given the expected calibration difficulties. Further, since top gas analysis is a critical tool for ensuring proper blast furnace operation, sources already have ample incentive to ensure accurate and consistent data. Thus, use of nitrogen tracing potentially presents a less costly, more precise way to determine the amount of blast furnace gas produced. That figure can then be used to precisely determine GHG emissions from combustion. To authorize the development of such more accurate and less burdensome options, we request that EPA amend the Proposed Rule to allow any alternate approach for determining the amount of process gas generated (and combusted) that has equal or greater accuracy than the current monitoring proposal.

Response: EPA refers the commenter to §98.3(i)(6) of Subpart A that allows the owner or operator to postpone initial calibration until the next scheduled maintenance outage if there are units and processes that operate continuously with infrequent outages. Such postponements shall be documented in the monitoring plan that is required under §98.3(g)(5).

The commenter is also referred to Table C-1 of Subpart C, which now includes a default high heat value and CO_2 emission factor for blast furnace gas. The Tier 1 methodology may be used for any fuel listed in Table C-1 that is combusted in a unity with a maximum rated heat input capacity of 250 mmBtu/hr or less. If eligible to use the Tier 1 methodology, mass or volume of fuel combusted can be taken from company records.

EPA has revised the use of Tier 3 in §98.33(b)(3) of Subpart C to be required only when a unit with a maximum rated heat input capacity greater than 250 mmBtu/hr that combusts any type of fuel listed in Table C-1 of this subpart (except MSW), unless the use of Tier 1 or 2 is permitted or Tier 4 is required. Tier 3 is also required for a unit with a maximum rated heat input capacity greater than 250 mmBtu/hr that combusts a fuel that is not listed in Table C-1 of this subpart provided that the use of Tier 4 is not required and the fuels provide ten percent or more of the annual heat input to the unit or to a group of units served by common supply pipe, as described in §98.36(c)(3).

EPA's approach makes use of existing data and methodologies to the extent feasible, and is consistent with the types of methods contained in other GHG reporting programs (e.g., the

California mandatory reporting rule, WCI, RGGI, TCR, and Climate Leaders). Because this approach specifies methods for each source category, it will result in data that are comparable across facilities. For consistency, EPA did not provide for alternative approaches as described by the commenter.

Commenter Name: Dan F. Hunter
Commenter Affiliation: ConocoPhillips Company
Document Control Number: EPA-HQ-OAR-2008-0508-0515.1
Comment Excerpt Number: 19

Comment: The calculation methodology (98.33) and Monitoring and QA/QC requirements (98.34) require clarification. The proposed regulatory language does not reflect the intent and understanding explained in the Preamble to the rule. The rule appears to clearly require fuel flow measurements under Tier 3 and Tier 4 calculation methodologies while for Tier 1 and Tier 2 it requires company records to be utilized to determine quantity of fuel combusted. The rule is unclear about how quantity of fuels combusted can be determined from company records. ConocoPhillips seeks EPA's confirmation of our interpretation that under Tier 1 and 2 calculation methodologies, the affected facilities may use other methods to estimate fuel flow to combustion devices such as rated capacities, load factors, hours of operation or conservative estimates of hours of operation, etc.

Response: EPA acknowledges the commenter's concerns, and has defined the term "company records" in §98.6 of the final rule. EPA believes that the revised definition provides appropriate guidance as to what records a facility may use to determine fuel consumption.

Commenter Name: Jack Gehring et al.
Commenter Affiliation: Caterpillar Inc.
Document Control Number: EPA-HQ-OAR-2008-0508-0499.1
Comment Excerpt Number: 23

Comment: EPA should clarify the following if it promulgates the Reporting Rule substantially as it has proposed: 1. That the "company records" from which fuel usage is derived under the Tier 1 and Tier 2 calculation methods may include, for example, natural gas billing records or estimates derived from such records rather than direct measurement (via fuel flow meters); 2. That data collection and calculations requirements applicable to individual stationary fuel combustion units (in proposed 40 CFR 98.33, 98.34 and 98.36) may be aggregated at the discretion of the facility, and fuel usage for Tier 1 and 2 calculation methods (for unlimited groups of units with aggregate rated heat input capacity of less than 250 mmBTU) can be derived from, for example, natural gas billing records rather than direct measurement (via fuel flow meters); 3. That facilities which are required to, or choose to, use Tier 3 calculation methods may utilize existing natural gas billing meters (including multiple meters at a single facility) to report facility wide GHG emissions if the relevant data concerning fuel properties is provided by natural gas suppliers; and 4. That facilities using the "common pipe configuration" option for reporting (in proposed 40 CFR 98.36(c)(3)) may utilize existing gas billing meters to satisfy the requirement to use a "calibrated fuel flow meter." Many of the clarifications requested are intended to ensure operational flexibility and make clear that, provided facilities have a reliable source of fuel usage information, they generally will be able to estimate emissions from individual units (or groups of units) and will not be required to install additional fuel meters to measure usage at each individual unit. This is a critical consideration, since requiring installation of fuel meters for each stationary fuel combustion unit will drive significant unnecessary expense and hamper each facility's ability to modify its operations as needed.

Response: See the Preamble and separate comment response document volume for the response on the method for calculating GHG emissions.

In preparation of the final rule, EPA believes it has clarified instructions regarding aggregation and common pipe provisions. EPA has retained the provision requiring fuel use in a common pipe configuration to be accurately measured by a calibrated fuel flow meter, noting that fuel billing meters can be used for this purpose. In addition, EPA acknowledges the commenter's concerns regarding the term "company records" in §98.6 of the final rule. EPA believes that the revised definition provides appropriate guidance as to what records a facility may use to determine fuel consumption.

Commenter Name: Leslie Bellas
Commenter Affiliation: National Lime Association (NLA)
Document Control Number: EPA-HQ-OAR-2008-0508-0520.1
Comment Excerpt Number: 24

Comment: 40 C.F.R. §98.34(e)(1) appears to require that all procedures identified must be followed to initially certify a CEMS. Based on our May 14 conference call with EPA, only one of the listed procedures must be followed to initially certify a CEMS. NLA proposes that 40 C.F.R. §98.34(e)(1) be revised to state that "For initial certification, use one of the following procedures:"

Response: EPA agrees that the proposed language could be confusing, and has added language to the final rule to clarify that any one of the alternate initial certification procedures for CO_2 CEMS is acceptable.

Commenter Name: Jeffrey L. Clark
Commenter Affiliation: Environmental Coordinator, Teck Alaska Incorporated
Document Control Number: EPA-HQ-OAR-2008-0508-0142
Comment Excerpt Number: 7

Comment: I oppose the inclusion of the quantity of electricity purchased by the facility. This again leads to double reporting. The same can be said about reporting indirect GHG emissions.

Response: This rule does not have a requirement for reporting electricity purchases or indirect emissions. See the Preamble and separate comment response document volume for the response on the general content of the annual emissions report.

Commenter Name: Dan F. Hunter
Commenter Affiliation: ConocoPhillips Company
Document Control Number: EPA-HQ-OAR-2008-0508-0515.1
Comment Excerpt Number: 25

Comment: The statement "All oil and gas flow meters" should be revised to "All liquid and gas flow meters." There currently are no QA/QC provisions for liquid flow meters used in support of the Tier 3 combustion emission calculations.

Response: EPA agrees that the proposed language was ambiguous, and changed the final rule to read as follows: "Each Fuel meter that provides fuel usage data for the GHG emissions reported under this part…" This does not explicitly specify liquid flow meters, but the Agency believes the provisions for liquid flow meters are implied.

Commenter Name: Michael DiMauro
Commenter Affiliation: Massachusetts Municipal Wholesale Electric Company (MMWEC)
Document Control Number: EPA-HQ-OAR-2008-0508-0580
Comment Excerpt Number: 7

Comment: The GHG Reporting Rule should allow all stationary combustion sources (not just Acid Rain units) the option to conform with applicable Part 75 procedures. Such an approach would be consistent with many NSPS rules (e.g. Subpart Da, Subpart Db, Subpart KKKK), which have gradually been incorporating Part 75 procedures as an acceptable alternative to 40 CFR 60 Appendix B and F for CEMS monitoring, fuel metering and fuel sampling. In particular, all stationary sources should be provided the option to: a) Conduct Fuel Meter Quality Assurance in accordance with 40 CFR 75 Appendix D procedures, performance specifications and testing timelines. Testing timelines should be based on QA operating quarters, not calendar quarters, and if feasible the option to perform fuel flow/load analyses to extend testing deadlines should also be adopted. Note that the Preamble (FR Page 16484, Column 1) indicates that EPA "recommends the use of fuel flow calibration methods in 40 CFR 75", but this language is not explicitly reflected in 98.34(d). Moreover, not only the use of Part 75 Calibration Methods, but also the use of Part 75 Test Cycle Timelines should be allowed under the GHG Reporting rule. b) Perform fuel sampling to determine high heat content in accordance with 40 CFR 75 Appendix D procedures, and also report this fuel heat content data, and use it in emission calculations, in accordance with 40 CFR 75 Appendix D procedures The 40 CFR 75 Appendix D procedures provide a well established and broadly accepted methodology for compliance monitoring and regulatory emission reporting, and are therefore well suited to support GHG Emission reporting.

Response: See the Preamble and separate comment response document volume for the response on the method for calculating GHG emissions.

EPA believes that the structure of the final rule mirrors the commenter's suggestion to a large extent. As stated in the Preamble, new methodologies in addition to the tiers have been added, allowing non-Acid Rain sources that monitor and report heat input according to Part 75 to use established Part 75 CO_2 emission calculation methods to meet the Part 98 reporting requirements.

Commenter Name: Keith Adams
Commenter Affiliation: Air Products and Chemicals, Inc.
Document Control Number: EPA-HQ-OAR-2008-0508-1142.1
Comment Excerpt Number: 26

Comment: The proposed rule requires all liquid and gaseous fuel flow meters to be calibrated initially and annually, or at the meter manufacturer's specified frequency, thereafter. This requirement fails to recognize that some fuel measurement device installations do not allow calibration without taking the fuel line out of service, thereby forcing a shutdown of the combustion/manufacturing process. In many instances, scheduled maintenance shutdowns for such equipment/processes will not occur on this prescribed frequency. Unless provisions are added to the proposed rule which provide relief from this required calibration frequency, manufacturing processes will be required to shutdown solely to complete the required calibration, resulting in significant cost, business disruption and, in many cases, increase environmental impacts from the inefficiencies of the start-up/shutdown activity. This need is comparable to provisions under many EPA rules regarding the repair of leaking VOC fugitive emissions components where repair would require a process shutdown, and instead the repair deadline is extended to the next scheduled maintenance shutdown. In most instances, the delay in calibration of a flow meter requiring a process shutdown would not materially compromise the annual emission estimate. This is particularly true for those combustion units using the simplest, cleanest fuels – there is typically less "drift" in the calibration of flow measurement devices for such clean fuels and such combustion units/processes often require less frequent maintenance turnarounds, exacerbating the need for extension of the calibration frequency. Air Products Comment: The rule should include provisions for an extension of the required flow meter calibration deadline (as well as the initial calibration, if appropriate) where the calibration would require removing the fuel supply from service. The calibration requirement should then be extended to the next scheduled maintenance shutdown for the impacted unit/process.
Response: See the Preamble, Section II. G., "Summary of Comments and Responses on Initial Reporting Year and Best Available Monitoring Methods," for a description of additional flexibility for monitoring methods in 2010.

EPA acknowledges the concerns of the commenters. The final rule clarifies that for units and processes that operate continuously with infrequent outages and use orifice, nozzle or venturi meters, the owner or operator may postpone the initial calibration or PEI (as applicable) until the next scheduled maintenance outage, and may similarly postpone the subsequent recalibrations and PEIs.

Regarding the ongoing QA requirements for fuel flow meters (except for orifice, nozzle, and venturi meters), the final rule has kept the annual requirement for successive required calibrations, but has also allowed calibration at the frequency as specified by the manufacturer or accepted industry consensus. For orifice, nozzle, and venturi meters, recalibration of the transmitters is required annually, supplemented by a primary element inspection (PEI) once every three years. For continuous processes, if the PEI cannot be performed safely without disrupting normal operation, it may be postponed until the next maintenance outage.

Commenter Name: Keith Adams
Commenter Affiliation: Air Products and Chemicals, Inc.
Document Control Number: EPA-HQ-OAR-2008-0508-1142.1
Comment Excerpt Number: 27

Comment: The proposed rule defines the alternate initial certifications for CO_2 CEMS systems under §98.34(e)(1)(i), (ii), and (iii). The propose rule language is not clear that any one of the certifications described in §98.34(e)(1)(i), (ii), and (iii) is acceptable. Clarify that any one of the alternate initial certifications under §98.34(e)(1)(i), (ii), and (iii) is acceptable by separating the (i), (ii), and (iii) options with "or".

Response: EPA agrees that the proposed language could be confusing, and has added language to the final rule to clarify that any one of the alternate initial certification procedures for CO_2 CEMS is acceptable.

Commenter Name: Linda Farrington
Commenter Affiliation: Eli Lilly and Company (Lilly)
Document Control Number: EPA-HQ-OAR-2008-0508-0680.1
Comment Excerpt Number: 28

Comment: The dates and results of the initial CEMS certification tests and major quality assurance tests performed on the CEMS during the reporting year (i.e., linearity checks, cylinder gas audits, and relative accuracy audit tests) are required to be submitted to the EPA as part of the verification data for the GHG emission report. This requirement is duplicative and not necessary because the results of CEMS QA/QC tests are already submitted to state or local regulatory authorities. Therefore, there is no need for EPA to require redundant reporting of this information. State and local regulatory authorities typically provide oversight for CEMS required by other regulatory programs and we believe they should provide oversight for CO_2 CEMS required by the proposed GHG reporting rule; thereby eliminating the need for EPA to verify the validity of CEMS data on an on-going basis.

Response: EPA believes that it is appropriate for reporters using the Tier 4 methods of Subpart C to submit the results of CEMS certification and QA tests directly to EPA. However, EPA has added language to §98.36(e)(2)(iv)(E) and (F) clarifying that sources must only submit the summarized results of these tests, rather than the complete results. EPA believes that this will reduce the burden on reporters. EPA has also clarified that no additional verification data is required to be reported for Acid Rain Program units or other units that report under Part 75 (see §98.36(e)(1)).

Commenter Name: Leslie Bellas
Commenter Affiliation: National Lime Association (NLA)
Document Control Number: EPA-HQ-OAR-2008-0508-0520.1
Comment Excerpt Number: 29

Comment: To determine the biogenic portion of CO_2 emissions from MSW combustion, 40 C.F.R. §98.34(f) requires sources to quarterly sample gases when the unit has been exclusively burning MSW for twenty-four hours. In the case of a lime plant, this requirement would mean that the kiln could not generate lime during sampling because burning only MSW would not generate the heat necessary for lime production. In many cases it would be difficult to burn only MSW as supplemental fuel such as coal might be required to keep the flame burning. Consequently, this sampling methodology would discourage the use of alternative fuels, such as MSW. Revise 40 C.F.R. §98.34(f) to also permit the use of fuel input data on a quarterly basis so that stack testing is not required. Utilizing fuel input data on a quarterly basis would adequately address EPA's concern about the variability of the fuel.

Response: EPA refers commenter to §98.33(e) and §98.34(d) of Subpart C for the final text on determining the biogenic portion of CO_2 emissions from MSW combustion. However, the requirement in §98.34(d) noted by the commenter has not changed given that an acceptable alternative method was not identified by EPA.

EPA notes the provisions of §98.34(d) of the final rule which provide instructions for determination of the biogenic portion of the CO_2 emissions from MSW combustion as follows: Perform the ASTM D7459-08 sampling and the ASTM D6866-08 analysis at least once in every calendar quarter in which MSW is combusted in the unit. Collect each gas sample during normal unit operating conditions while MSW is the only fuel being combusted for at least 24 consecutive hours or collect each gas sample for as long as is necessary to obtain a sample large enough to meet the specifications of ASTM D6866-08. Use the results from ASTM D7459-08 to separate CO_2 emissions into the biogenic and non-biogenic fraction, using the average proportion of biogenic emissions of all samples analyzed during the reporting year. EPA further notes that the provisions provide a choice of collection options for the gas samples.

Commenter Name: Linda Farrington
Commenter Affiliation: Eli Lilly and Company (Lilly)
Document Control Number: EPA-HQ-OAR-2008-0508-0680.1
Comment Excerpt Number: 29

Comment: The EPA solicits comments on ways to ensure that the feed rate of solid fuel to a combustion device is accurately measured. Lilly suggests the EPA allow the use of engineering calculations and best available information to estimate solid fuel consumption. An example of a reasonable engineering calculation would be to calculate the amount of solid fuel combusted based upon the amount of steam generated and boiler efficiency. This could provide more accurate data than fuel mass measurement, especially for units where retrofits may be required. Lilly does not believe it is necessarily beneficial or cost effective to require the installation of weighing devices for direct measurement of solid fuel usage.

Response: EPA has extended the use of steam production and combustion unit efficiency to calculate CO_2 emissions to other solid fuels in addition to municipal solid waste. These parameters may also be used to quantify the amount of biomass combusted in a unit.

Commenter Name: Jeff A. Myrom
Commenter Affiliation: MidAmerican Energy Holdings Company
Document Control Number: EPA-HQ-OAR-2008-0508-0581.1
Comment Excerpt Number: 31

Comment: EPA solicited comment on ways to ensure that the feed rate of solid fuel to a combustion device is accurately measured (page 16485). Facilities already have sufficient motivation to accurately report emissions from solid fuel combustion (and thus the quantification of that fuel) due to potential Clean Air Act violation fines of up to $32,500 per day as well as other administrative, civil, and criminal measures. Thus, EPA does not need additional measures to ensure that total fuel use is measured correctly.

Response: EPA appreciates the commenter's concern, and has simplified the rule. The revised rule states that fuel combustion may be determined from company records. Also, the use of steam production and combustion unit efficiency to calculate CO_2 emissions is extended to other solid fuels in addition to municipal solid waste. These parameters may also be used to quantify the amount of biomass combusted in a unit.

Commenter Name: Leslie Bellas
Commenter Affiliation: National Lime Association (NLA)
Document Control Number: EPA-HQ-OAR-2008-0508-0520.1
Comment Excerpt Number: 34

Comment: The Preamble, 74 Fed. Reg. at 16,484, and Table 8 in the Technical Support Documentation indicate that 40 C.F.R. §§98.34(c) and (d)(3) require Tier 2 and Tier 3 facilities using solid fuel to sample weekly and composite weekly sample results into a monthly carbon content value that is reported. However, 40 C.F.R. §§98.34(c) and 98.34(d)(3) also incorporate by reference several ASTM standards, including ASTM D2234 (Standard Practice for Collection of a Gross Sample of Coal), which permits less frequent sampling. To the extent that the specific sampling procedures in 40 C.F.R. §§98.34(c) and (d)(3) conflict with the general reference to ASTM D2234, the requirements in 40 C.F.R. §§98.34(c) and 98.34(d)(3) should control. Request for Clarification and NLA's Proposal: The Proposed Rule should clearly state that the incorporation by reference of ASTM D2234 at 40 C.F.R. §98.7 does not supersede the sampling frequency requirements in 40 C.F.R. §§98.34(c) and 98.34(d)(3). Adherence to the sampling requirements in 40 C.F.R. §§98.34(c) and 98.34(d)(3) will provide a minimum, consistent sampling frequency among Tier 2 and Tier 3 facilities. ASTM D2234, in contrast, requires a sampling frequency that is calculated based on plant-specific factors, possibly as often as daily or even several times daily.

Response: EPA has revised §98.34 to clarify that only the methods listed in that section may be used for fuel sampling and analysis for Tiers 2 and 3, regardless of any other methods that are incorporated in §98.7. ASTM D2234, though incorporated by reference at §98.7, is not listed in §98.34, and therefore may not be used for the purposes of Subpart C.

Commenter Name: Leslie Bellas
Commenter Affiliation: National Lime Association (NLA)
Document Control Number: EPA-HQ-OAR-2008-0508-0520.1
Comment Excerpt Number: 47

Comment: The Preamble, 74 Fed. Reg. at 16,523 and 40 C.F.R. 98.194(d) states that the NLA Protocol is incorporated by reference at 98.7. However, 40 C.F.R. 98.7 does not incorporate the NLA Protocol.

Response: The NLA CO_2 Emissions Calculation Protocol for the Lime Industry -- English Units Version is incorporated by reference into the final rule at §98.7.

Commenter Name: Lorraine Krupa Gershman
Commenter Affiliation: American Chemistry Council (ACC)
Document Control Number: EPA-HQ-OAR-2008-0508-0423.2
Comment Excerpt Number: 59

Comment: For §§98.34(c)(1) and (d)(3), the composition of natural gas does not change often enough to warrant monthly sampling. At most, ACC recommends annual sampling. ACC recommends eliminating the source sampling and testing of fuels, including pipeline natural gas supplies, to reduce the excessive burden of each facility needing to sample and analyze the fuel when instead it could be more efficiently sampled and analyzed only once by the supplier. Additionally, the sampling frequency should be yearly or whenever the supplier changes the source of the fuel such that the fuel composition may be likely to change. These fuels will not appreciably change in composition from month to month. As an alternative, requiring these fuels to be sampled twice per year would align with many custom fuel sampling schedules for determining sulfur content of natural gas.

Response: EPA acknowledges the commenters' concerns regarding natural gas sampling costs, and has revised the §98.34 as follows: for natural gas, semiannual sampling and analysis is required.

Commenter Name: Dan F. Hunter
Commenter Affiliation: ConocoPhillips Company
Document Control Number: EPA-HQ-OAR-2008-0508-0515.1
Comment Excerpt Number: 24

Comment: In 98.34(c)(1), sources combusting natural gas require monthly sampling and analysis for HHV. Monthly collection of production fuel gas samples can be burdensome. The composition of production field gas at natural gas processing facilities does not vary enough to warrant monthly analysis of HHV. Production field gas should be measured no less frequent than quarterly. Monthly sampling and analysis of refinery fuel gas is reasonable. The ability to justify a longer frequency should be considered for the final rule. ConocoPhillips encourages EPA to develop an approach under Tier 2 that would allow facilities to reduce the frequency of testing once the measured data demonstrates the HHV of the natural gas meets certain statistical requirements (variability) and then periodic testing to demonstrate the measurement results remains statistically equivalent to the established HHV. Note that under 98.3 6(d)(1)((ii)(A), for Tier 2 calculation methodology, the rule requires submittal of the monthly fuel HHV data. This requirement would need to be modified to meet the required measurement frequency.

Response: EPA acknowledges the commenters' concerns regarding natural gas sampling costs, and has revised the rule to require semiannual sampling and analysis.

Commenter Name: Paul R. Pike
Commenter Affiliation: Ameren Corporation
Document Control Number: EPA-HQ-OAR-2008-0508-0487.1
Comment Excerpt Number: 14

Comment: Our acceptance of a requirement for ARP units to rely on their Part 75 cumulative CO_2 mass emissions estimates is limited to this rulemaking, and does not automatically extend to rules regulating emissions of CO_2. CO_2 mass emissions data reported under Part 75 are affected by a rule requiring "bias" adjustment of volumetric flow monitor data based on the results of a statistical analysis of relative accuracy test audit ("RATA") data comparing the flow monitor's response to an EPA reference method. If the RATA data are determined to be "biased" based on a one-tailed test, all hourly flow monitor data from that RATA forward are adjusted "upward" by a calculated bias adjustment factor ("BAF") until a new RATA is performed. We believe that the test, which is based on data from a single stack test, does not represent true "bias." The test also does not allow for adjustment of data downward if the test indicates that the "bias" in the data is positive. Adjustment of volumetric flow monitoring data in this manner can result in a significant difference in the reported, versus measured, CO_2 mass emissions. When EPA has relied upon Part 75 data in other regulatory programs, like the NSPS, EPA has always made clear that sources are to use the unadjusted data, which is also recorded. However, because Part 75 does not require calculation of hourly CO_2 mass emissions in its "unadjusted" form (only unadjusted hourly volumetric flow data are reported), using unadjusted data for the purposes of this rule would require additional calculations and software changes for ARP units. ARP units could not rely on their reported cumulative values. As a result, Ameren is not seeking an alternative to report unadjusted data at this time, but may do so in a future rulemaking if the data are to be used for regulatory purposes.

Response: See the Preamble, Section III. C., the Subpart D comment response document volume, and the response to comment EPA-HQ-OAR-2008-0508-0956.1 excerpt 20 for the rationale for using substitute data reported under Part 75.

Under this rulemaking, EPA is not revising Part 75 reporting requirements. EPA is keeping GHG monitoring requirements consistent with current monitoring because the Agency does not want to require two sets of data which would add cost and complexity.

Commenter Name: Trudy Richter
Commenter Affiliation: Minnesota Resource Recovery Association (MRRA)
Document Control Number: EPA-HQ-OAR-2008-0508-0546
Comment Excerpt Number: 1

Comment: The MRRA objects to the proposed rule in section (f) on page 16637 of the Federal Register, Volume 74, No. 68 that requires a determination of the biogenic portion of CO_2 emissions utilizing ASTM D6866-06a and ASTM D 7459-08. The rule requires that the tests be performed every calendar quarter. This testing methodology and frequency are burdensome for waste to energy facilities. In Minnesota, we have gathered information every five years from waste sorts performed consistent with applicable rules. These sorts indicate that the waste stream components have not varied significantly in the last twenty years and that approximately 66% of the waste, when combusted, would produce biogenic CO_2. Testing quarterly is totally unnecessary and the rule should offer acceptable alternatives as follows: 1) No testing is required unless the facility proposes to sell its renewable electricity to the grid; and 2) Testing only applies if there is parity with landfill gas recovery systems also performing an equal amount of testing; and 3) Testing only once every three years is adequate (in conjunction with other stack testing) or 4) Allowing in the alternative, the use of waste sort data to calculate the biogenic portion of CO_2.

Response: EPA disagrees with the commenter, and believes that quarterly sampling is necessary given the potential for variation in different solid waste streams across the municipal waste combustor population.

Commenter Name: Obadiah Bartholomy
Commenter Affiliation: Sacremento Municipal Utility District
Document Control Number: EPA-HQ-OAR-2008-0508-0540.1
Comment Excerpt Number: 2

Comment: SMUD believes there is a need for flexibility in metering of biogas fuel in locations offsite from the facility where the fuel is to be combusted. The electric utility industry is experiencing unprecedented change in the kinds of fuels used to generate electricity and any mandatory reporting rule should facilitate such innovation. Heretofore, biogenic gas or biogas (such as landfill gas and digester gas) has been burned for energy at the same location the gas has been generated. But new arrangements are being used to generate gas in one location and transmit it to generators in some cases states away for convenient electricity generation. One model is to connect a landfill or digester with a dedicated pipeline to a gas-fired power plant. Another model is to purchase biogas from a remote location, clean the gas to pipeline gas quality specifications, and transmit it through common pipelines to the LDC's system, again for combustion at a gas-fired power plant. These kinds of agreements enable more efficient conversion of chemical energy to electrical energy because combined-cycle gas plants are among the cleanest and most efficient generating units in use, whereas many on-site combustion technologies are less efficient and face challenges in managing associated criteria pollutants. Consequently, with greater conversion efficiencies, the relative emissions of GHG are reduced per unit of energy (MWh) produced and consumed. The EPA should make sure that its reporting rule is consistent with the more efficient use of biogenic gas. Many electric generating units (EGUs) that burn natural gas are subject to EPA's acid rain program (ARP). Subpart D of the Proposed Rule (proposed §98.46(a)) specifies that the Data Reporting Requirements for EGUs subject to the ARP are the same as some but not all of those specified in Subpart C, §98.36. However, for EGUs subject to the ARP, there does not appear to be a clear nexus between Subpart D and the calculation methodologies in Subpart C with respect to biogenic GHG emissions. Furthermore, it is unclear from Subpart C how such EGUs should report biogas co-mingled in either dedicated or common supply pipelines that deliver gas for combustion in power plants. While the Proposed Rule does address metering of gas drawn from common supply pipelines in certain situations, there is ambiguity in the Proposed Rule about separate metering and reporting of co-mingled gas. Landfill or digester gas piped to power plants from remote locations is ultimately burned and generates GHG emissions. The proposed regulation clearly evidences an intent to report these emissions separately from the combustion of natural gas. (See proposed §98.33(e)) However, if such biogas is co-mingled in a pipeline it becomes indistinguishable from natural gas so that, arguably, the same gas is not burned when it is withdrawn at the purchaser's power plant. If the biogas is not accounted for then there is gas in the interstate system that leads to GHG emissions that are not reported separately. Rather than abandon efforts to track emissions from biogas transmitted by pipeline, a simple solution would be to provide for metering the gas at the point of injection and backing out the same amount from the amount withdrawn by the owner of the biogas. In this way, the same amount of biogas injected into the pipe is accounted for. If EPA amends its Proposed Rule to provide a method for separate metering and netting of such co-mingled biogas the intent of the rule is preserved and whatever attributes or benefits that may come with purchasing a renewable or recycled product is preserved to the purchaser. This change should promote use of such gas in higher efficiency, combined cycle gas-fired power plants rather than at lower efficiency combustion units at landfills or digesters.

Response: See Subpart D for a description of the reporting requirements for EGUs over and above the requirements under 40 CFR Part 75.

In §98.33(e)(2), EPA has added a provision allowing facilities to calculate biogenic CO_2 emissions from the combustion of biogas using Tier 1 methods, provided that the quantity of the biogas combusted can be determined from company records, as defined in §98.6, and default factors for the fuel are provided in Table C-1. Biogas has been added to Table C-1, and is listed as "Biogas (captured methane)." Also, for premixed fuels that contain biomass and fossil fuels (e.g., mixtures containing biodiesel), best available information can be used to determine the mass of biomass fuels and document the procedure used in the GHG Monitoring Plan required by §98.3(g)(5).

Commenter Name: Lisa D. Schmidt
Commenter Affiliation: Dow Corning Corporation
Document Control Number: EPA-HQ-OAR-2008-0508-0562
Comment Excerpt Number: 3

Comment: The timeline to respond to data requests from the EPA needs to be extended to a minimum of 30 days. The current proposal of seven days is insufficient to provide a thorough response to any request for detailed technical information.

Response: EPA acknowledges the commenters' concerns. In §98.36(e)(3) of the final rule, EPA has allowed owners or operators 30 days from receipt of a written request for information to respond to that request.

Commenter Name: Laurie Zelnio
Commenter Affiliation: Deere & Company
Document Control Number: EPA-HQ-OAR-2008-0508-0355.1
Comment Excerpt Number: 5

Comment: The Tier 3 calculation methodology set forth in §98.33(a)(3) states: "For liquid and gaseous fuels, the volume of fuel combusted is measured directly, using fuel flow meters (including gas billing meters)." At Deere's affected facilities, the natural gas billing meters are installed and maintained by our utility companies. As the meters do not belong to our affected facilities, calibrating the meters becomes an ownership issue. In the proposed rule, calibration of natural gas billing meters is exempted under §98.34(d)(1) Monitoring and QA/QC Requirements as follows: "All oil and gas flow meters (except for gas billing meters) shall be calibrated prior to the first year for which GHG emissions are reported... and recalibrated annually or at the minimum frequency specified by the manufacturer." However, the calibration of natural gas billing meters is not exempted under alternative reporting requirements or verification data. To effectively implement this exemption, Deere recommends the phrase "except for gas billing meters" be added to §§98.38(c)(3) and 98.35(d)(1)(iii)(F).

Response: EPA acknowledges the concerns of the commenter. Section 98.34 of the final rule has been clarified to exempt fuel billing meters from the calibration requirement, "provided that the supplier and the unit(s) combusting the fuel do not have any common owners and are not owned by subsidiaries or affiliates of the same company."

Commenter Name: Gary Moore
Commenter Affiliation: Pensacola Plant of Ascend Performance Materials LLC
Document Control Number: EPA-HQ-OAR-2008-0508-0366.1
Comment Excerpt Number: 8

Comment: In the Preamble to the rule on page 16483 it states: "In addition, EPA is proposing that a facility may use the Tier 3 calculation methodology to calculate facility-wide CO_2 emissions (rather than unit-by-unit emissions) when the same liquid or gaseous fuel is used across the facility and a common direct measurement of fuel consumed is available (e.g., a natural gas meter at the facility gate). This flexibility is consistent with existing protocols and methodologies allowed by EPA in existing programs." In §98.36(c)(1) only the aggregation of small units is allowed. Allowing the option of aggregation of emissions for all sources (including boilers, combustion turbines, process heaters, natural gas fueled hydrogen plants, control devices) using the common fuel and a single billing meter would ease reporting and not reduce data quality. Furthermore, this reduces propagation of error issues due to summing up emissions from many meters and also allows the Agency to more accurately track natural gas from production to end use. We propose that the Agency allow the use of natural gas fence line billing meters or invoices from the distribution company to be used in Tier 3 emission calculations for all emissions from natural gas. Other fuels combusted would be reported separately for each individual combustion unit.

Response: EPA acknowledges the concerns of the commenter and has revised the rule to allow more flexibility in reporting. For units that use Tiers 1, 2, and 3 to calculate CO_2 mass emissions, the cumulative 250 mmBtu/hr heat input capacity limit on the aggregation of units into a group has been dropped. Rather, the 250 mmBtu/hr restriction applies only to the individual units in the group. Therefore, for reporting purposes, individual units with maximum rated heat input capacities of 250 mmBtu/hr or less may be aggregated without limit into a single group, provided that the Tier 4 methodology is not required for any of the units, and all units in the group use the same Tier for any common fuel(s) that they combust. Units with maximum rated heat inputs greater than 250 mmBtu/hr using Tiers 1, 2, and 3 must report as individual units, unless they burn the same type of fuel (oil or gas) provided by a common pipe or supply line; in that case, the owner or operator may opt to use the highest Tier required for a grouped unit for the calculation method with the common pipe reporting provisions in §98.36. Units using Tier 4 must report as individual units unless they share a monitored common stack; in that case, the common stack reporting provisions of §98.36 may be used.

Commenter Name: See Table 4
Commenter Affiliation:
Document Control Number: EPA-HQ-OAR-2008-0508-0455.1
Comment Excerpt Number: 8

Comment: Under proposed §98.34, stationary fuel combustion sources subject to Tier Four monitoring requirements would be required to upgrade their existing CEMS if (1) the CEMS gas monitor is neither a CO_2 concentration monitor nor an O_2 concentration monitor and (2) if a flow monitor is not already installed. The Class of '85 believes that concentration monitors are not necessary to accurately report CO_2 emissions from EGUs. Many EGUs with CEMS currently utilize other means for calculating their CO_2 emissions that are equally as accurate as and less costly than installing new monitors. Several of these EGUs, which currently report CO_2 emissions to state and regional mandatory GHG programs, use fuel emission factors and EPA approved methodologies to accurately calculate and report their CO_2 emissions. Required upgrades to CEMS would impose an unnecessary economic burden on facilities. Upgrading an EGU's CEMS to include a concentration monitor can cost well over $50,000 per unit, plus costs associated with certification, ongoing testing, and maintenance. Furthermore, the Agency's proposed implementation schedule would not provide sufficient time to acquire, install, and test new concentration monitors prior to beginning mandatory reporting in January 2010. For these reasons, the Class of '85 believes that EPA should not require EGUs with existing CEMS to upgrade their systems to include a concentration monitor. Instead, EPA should allow these EGUs to utilize fuel emission factors and EPA approved methodologies to calculate their CO_2 emissions. At the least, EPA should extend its proposed reporting deadline to allow adequate time for EGUs to upgrade their CEMS.

Response: See the Preamble, Section II. L., on General Monitoring Requirements for the overall rationale for methodologies required under this rule, and the response to comment EPA-HQ-

OAR-2008-0508-0909.1 excerpt 4 and EPA-HQ-OAR-2008-0508-0580 excerpt 10 for the rationale for methodologies required under Subpart C.

EPA is requiring the use of CEMS for solid fossil fuel-fired units due to the complexity of monitoring solid fuel consumption and the heterogeneous nature of the solid fuels. EPA has considered the commenter's analysis, but disagrees with the commenter's assessment of the burden associated with installing and maintaining the concentration and volume monitors that the rule requires be added to an existing CEMS. In the revised rule, EPA has clarified that if the unit in question meets all six criteria for Tier 4 to apply. EPA's estimates of monitoring costs are averages for a representative facility and may not represent the actual cost in individual circumstances. Note that EPA's cost estimates are annualized and do not widely differ from the capital cost cited in this comment. Further detail on the engineering cost analysis for Subpart C can be found in RIA (EPA-HQ-OAR-2008-0318-002) Section 4.3.

Commenter Name: John L. Wittenborn et al.
Commenter Affiliation: Steel Manufacturers Association (SMA) and Specialty Steel Industry of North America (SSINA)
Document Control Number: EPA-HQ-OAR-2008-0508-0518.1
Comment Excerpt Number: 8

Comment: Many steel facilities have natural gas burners above the 250 MMBTU threshold and therefore would be subject to the proposed Tier III reporting thresholds, which would require monthly sampling of the carbon content of natural gas. We do not believe that monthly sampling of pipeline quality natural gas is warranted. Such a requirement is inconsistent with methods EPA previously has found acceptable under Title IV. The Title IV requirements allow CO_2 calculations based on fuel flow measurements and heat content values supplied by natural gas utilities. If EPA believes that this is not sufficient to extrapolate a reasonable value for average carbon content, they should require that natural gas suppliers sample their product and provide the data to customers along with heating values. It is unreasonable to require each consumer to sample the same fungible commodity material.

Response: EPA acknowledges the commenters' concerns regarding natural gas sampling costs, and has relaxed the natural gas sampling requirement to semiannual sampling and analysis. Data provided by the fuel suppliers may be used in some circumstances.

Commenter Name: See Table 4
Commenter Affiliation:
Document Control Number: EPA-HQ-OAR-2008-0508-0455.1
Comment Excerpt Number: 10

Comment: Under proposed §98.43, EGUs subject to the requirements of the Acid Rain Program would continue to monitor and report CO_2 mass emissions in accordance with the monitoring requirements of 40 C.F.R. Part 75. Under Part 75, certain distillate oil and natural gas acid rain affected units may use alternative monitoring methods in lieu of CEMS. The Class of '85 supports this decision to continue the use of time-proven monitoring techniques.

However, under proposed §§98.43(b) and 98.44(b), EGUs not subject to the Acid Rain Program would be required to calculate CO_2 emissions and follow the quality assurance and quality control procedures identified in the four-tiered system of Subpart C of the Proposal. Within this four-tiered system, distillate oil and natural gas EGUs that are not subject to the Acid Rain Program may elect to employ the monitoring methods of Tier Four, as it is available to a unit of any size combusting any type of fuel. Tier Four, however, only allows monitoring via CO_2 or O_2 concentration monitors or flow CEMS, which must be quality assured in accordance with Part 75 requirements. Importantly, Tier Four does not include the alternative monitoring methods found in Appendices D and G of Part 75. If the alternative monitoring methods of 40 C.F.R. Part 75 are acceptable for measuring, reporting, and quality assuring CO_2 emissions from acid rain affected EGUs, then it seems only logical that they should be acceptable for measuring, reporting, and quality assuring CO_2 from non-acid rain affected units. Therefore, the Class of '85 believes that the Agency should allow EGUs that are not subject to the Acid Rain Program to monitor and report CO_2 mass emissions in accordance with the monitoring requirements of 40 C.F.R. Part 75, including the alternative methods allowed under Appendices D and G of Part 75.

Response: EPA has added Part 75 methodologies in Subpart C that may be used by sources that are currently required to report heat input data under Part 75, but are not required to report CO_2 mass emissions. The new methodologies allow these sources to use their Part 75 heat input data together with one of the CO_2 emissions Calculation Methodologies in Part 75 to meet Part 98 CO_2 emissions reporting requirements.

Commenter Name: Janice Adair
Commenter Affiliation: Western Climate Initiative (WCI)
Document Control Number: EPA-HQ-OAR-2008-0508-0443.1
Comment Excerpt Number: 11

Comment: A minimum accuracy may also be needed for fuel flow meters when fuel consumption is used to calculate GHG emissions. For quality-assurance purposes, U.S. EPA proposes that liquid and gaseous fuel flow meters at facilities subject to the more advanced Tier 3 methods for stationary combustion would have to be calibrated prior to the first reporting year. Meter accuracy is not prescribed, however, so meters with poor accuracy could remain in place as long as they are calibrated to manufacturer specifications. WCI recommends that U.S. EPA consider a documented minimum accuracy for meters that play a significant role in the calculation of facility GHG emissions. At minimum, we recommend inclusion of a provision that when new flow meters are installed that will be used to calculate facility GHG emissions, the meters be specified as accurate to + 5 percent. In a future market system, accurate emissions measurement will become especially important. With accurate metering and proper sampling, fuel-based methods can be as effective as more costly continuous emissions monitoring systems.

Response: EPA concurs and has added a five percent accuracy specification to §98.3. This specification must be met by March 31, 2010, except for flow meters described above that qualify for deadline extensions; these meters must meet the specification at the time of their next scheduled calibration.

Commenter Name: Edward N. Saccoccia
Commenter Affiliation: Praxair Inc.
Document Control Number: EPA-HQ-OAR-2008-0508-0977.1
Comment Excerpt Number: 7

Comment: The proposed rule requires all liquid and gaseous fuel flow meters to be calibrated initially and annually, or at the meter manufacturer's specified frequency, thereafter. This requirement fails to recognize that some fuel measurement device installations do not allow calibration without taking the fuel line out of service, thereby forcing a shutdown of the combustion/manufacturing process. In many instances, scheduled maintenance shutdowns for such equipment/processes will not occur on this prescribed frequency. Unless provisions are added to the proposed rule which provide relief from this required calibration frequency, manufacturing processes will be required to shutdown solely to complete the required calibration, resulting in significant cost, business disruption and, in many cases, increase environmental impacts from the inefficiencies of the start-up/shutdown activity. This need is comparable to provisions under many EPA rules regarding the repair of leaking VOC fugitive emissions components where repair would require a process shutdown, and instead the repair deadline is extended to the next scheduled maintenance shutdown. In most instances, the delay in calibration of a flow meter requiring a process shutdown would not materially compromise the annual emission estimate. This is particularly true for those combustion units using the simplest, cleanest fuels – there is typically less "drift" in the calibration of flow measurement devices for such clean fuels and such combustion units/processes often require less frequent maintenance turnarounds, exacerbating the need for extension of the calibration frequency. The rule should include provisions for an extension of the required flow meter calibration deadline (as well as the initial calibration, if appropriate) where the calibration would require removing the fuel supply from service. The calibration requirement should then be extended to the next scheduled maintenance shutdown for the impacted unit/process.

Response: EPA acknowledges the concerns of the commenters. Section 98.34 of the final rule clarifies that for units and processes that use a venturi, orifice, or nozzle meter and operate continuously with infrequent outages, the owner or operator may postpone the initial calibration or PEI (as applicable) until the next scheduled maintenance outage, and may similarly postpone the subsequent recalibrations and PEIs.

Commenter Name: Paul R. Pike
Commenter Affiliation: Ameren Corporation
Document Control Number: EPA-HQ-OAR-2008-0508-0487.1
Comment Excerpt Number: 13

Comment: Proposed §§98.44 - 98.46 repeat requirements that are already set out either in Part 75 or in Subpart C. The CO_2 data that were reported under Part 75 will either be Part 75 quality-assured data, or data estimated using Part 75 missing data procedures. It also is not necessary to require in this rule that such units "continue to monitor and report" CO_2 emissions under Part 75, as required under §98.43, or to specify under this subpart the meaning of terms, as stated in §98.48. Ameren supports allowing ARP units to report using the cumulative CO_2 mass emissions estimates reported under Part 75; however, we believe that §98.43 could be revised to simplify Subpart D.

Response: EPA has included rule language that may appear to be redundant in order to provide clarity concerning requirements under Part 75 and Part 98.

Commenter Name: Vince Brisini
Commenter Affiliation: RRI Energy Inc. (RRI)
Document Control Number: EPA-HQ-OAR-2008-0508-0618.1
Comment Excerpt Number: 7

Comment: U.S. EPA should allow companies to use the alternative monitoring methods found in Appendices D and G of Part 75 both for EGUs subject to the Acid Rain Program (Part 75) and those not subject to Part 75. Under its proposed GHG reporting rule, U.S. EPA proposes to allow distillate oil and natural gas EGUs that are not subject to the Acid Rain Program to employ the monitoring methods of Tier 4. However, Tier 4 specifies that CO_2 or O_2 concentrations must be monitored through CEMS and quality assured in accordance with Part 75 requirements. The main discrepancy between Part 75 and the current proposed GHG reporting rule is that Tier 4 methodology specified in the 0110 rule does not include the alternative monitoring methods found in Appendices D and G of Part 75. If U.S. EPA allows alternative monitoring methods for EGUs subject to Part 75 of the Acid Rain Program, it should also allow companies to apply all Part 75 methodologies to non-acid rain affected units.

Response: EPA has added new methods for sources that are currently required to report heat input data under Part 75, but are not required to report CO_2 mass emissions. The methods allow these sources to use their Part 75 heat input data together with one of the CO_2 emissions Calculation Methodologies in Part 75 to meet Part 98 CO_2 emissions reporting requirements.

Commenter Name: Michael W. Stroben
Commenter Affiliation: Duke Energy Corporation
Document Control Number: EPA-HQ-OAR-2008-0508-0407.1
Comment Excerpt Number: 18

Comment: Under EPA's proposal, Subpart C facilities that burn landfill gas would be required to perform daily sampling of the carbon content of the gas they receive when using the Tier 3 calculation method. In situations where the landfill is already sampling the carbon content of the gas on a daily or continuous basis or will be doing so under this rule the downstream facility should not be required to also perform sampling. The facility should be allowed to use the data provided by the gas supplier. It makes no sense to have both the landfill gas supplier and the facility using the gas to perform the same sampling.

Response: See the response to comment EPA-HQ-OAR-2008-0508-0540.1 excerpt 2, for an explanation of additional flexibility for characterizing biogas. The Agency has revised the final rule to clarify that fuel sampling and analysis data provided by the supplier may be used in the emission calculations.

Commenter Name: Stephen E. Woock
Commenter Affiliation: Weyerhaeuser Company
Document Control Number: EPA-HQ-OAR-2008-0508-0451.1
Comment Excerpt Number: 21

Comment: If EPA ultimately decides that the fuel factors (i.e., HHV and carbon content) must be determined by periodic analytical testing, then these determinations can be accomplished in a more appropriate timeframe rather than testing endlessly. Continuous monthly fuel testing will not enhance the accuracy of the GHG calculations, and will impose an unnecessary level of additional expense and burden on reporters. Because the properties of commonly used fuels, such as natural gas, oil, gasoline, etc. do not change significantly, once an initial fuel characterization is completed for a facility any re-testing should only be necessary infrequently. For example, if a different supplier is used, re-testing could be imposed. In addition, forest product industry specific fuel characteristics, such as pulping spent liquor and bark also do not change significantly over time to warrant monthly testing. The following describes how the fuel factors should be determined for the different fuels: 1. Natural gas: The HHV and carbon content of natural gas does not change significantly over time. This is due to contractual fuel guarantees with the supplier, who guarantees specific fuel properties, in particular the heating value. Initial fuel characterization would be provided by the supplier, with review of the supplier's fuel factors annually. 2. Oil: The HHV and carbon content of natural gas does not significantly change over time. This is due to contractual fuel guarantees with the supplier, who guarantees specific fuel properties. In addition, oil is typically purchased in large quantities and stored onsite. The fuel properties of this blended, homogeneous mix of oil in these large storage tanks will not change rapidly, and to continue to retest monthly out from the same storage tank is unreasonable. Initial fuel characterization would be provided by the supplier, with review of the supplier's fuel factors annually. 3. Coal: The HHV and carbon content of coal does not significantly change over time. This is due to contractual fuel guarantees with the supplier, who guarantees specific fuel properties. Coal is typically purchase in large quantities and stored onsite. Continuous deliveries of coal are added to the storage pile. Initial fuel characterization would be provided by the supplier, with review of the supplier's fuel factors annually. 4. Wood residuals at Pulp Mills: Wood residuals, mostly bark from trees, are generated in large quantities and stored onsite. Weyerhaeuser proposes an alternative GHG calculation approach, which will not require any fuel testing. In our comment #7 below, we describe an accurate and reliable methodology to calculate GHG emission from all solid fuels. This methodology is already allowed in this proposed rule for municipal solid waste (MSW) combustion units. It also should be allowed for the calculation of GHG emissions from wood residuals, which will eliminate an unnecessary and costly fuel testing program. 5. Spent pulping liquor: Spent pulping liquor is generated in large quantities and stored temporarily in large tanks before it is combusted for inorganic chemical and biomass energy recovery. During this temporary storage the large quantities of spent pulping liquor blend and homogenize the material's properties. Although spent liquor properties may differ between facilities, the spent liquor at each site will exhibit consistent properties. Therefore, after an initial fuel characterization is conducted the material could be retested on a longer, more representative frequency schedule, such as annually or every two years.

Response: The mandatory monthly fuel sampling and analysis requirements for traditional fossil fuels have been dropped from Tiers 2 and 3. Section 98.34 has been revised to require that natural gas be sampled semiannually. For fuel oil and coal, a representative sampling is required for each fuel lot, i.e., for each shipment or delivery. For other liquid fuels and biogas, quarterly sampling is required. For other solid fuels, excluding municipal solid waste, weekly composite sampling with monthly analysis is required. For other gaseous fuels, the daily sampling requirement has been retained, but only for facilities with existing equipment in place that is capable of providing the data. Otherwise, weekly sampling is required, which may be postponed in favor of monthly sampling until 2011 if new equipment must be purchased or if existing equipment must be upgraded to meet the weekly sampling and analysis requirements.

The final rule clarifies that fuel sampling and analysis data provided by the supplier may be used in the emission calculations, and that fuel billing meters may be used to quantify fuel consumption. To simplify the emission calculations in Tiers 2 and 3, averaging of HHV and carbon content data is permitted if these data are obtained at least at the minimum frequency specified in §98.34. If the results of fuel sampling are received monthly or more frequently, the weighted annual average high heat value shall be calculated using Equation C-2b. If the results of fuel sampling are received less frequently than monthly, then the annual average HHV shall be calculated using the arithmetic average HHV for all valid samples for the year. However, regardless of the sampling frequency, the owner or operator must use the results of all available valid fuel analyses in the emissions calculations.

EPA appreciates your comment and has allowed the use of steam production and combustion unit efficiency to calculate CO_2 emissions to be extended to other solid fuels in addition to municipal solid waste. These parameters may also be used to quantify the amount of biomass combusted in a unit.

Spent pulping liquor is not subject to Subpart C, but is addressed in Subpart AA. See the Preamble, Section III. AA., and separate Pulp and Paper response to comment document for EPA's response on spent pulping liquor measurement requirements.

Commenter Name: Angela Burckhalter
Commenter Affiliation: Oklahoma Independent Petroleum Association (OIPA)
Document Control Number: EPA-HQ-OAR-2008-0508-0386.1
Comment Excerpt Number: 23

Comment: EPA proposes to require reporters determine the carbon content for natural gas monthly. Natural gas produced at oil and gas production facilities is used to run many combustion units, and its composition does not change appreciably over time. If the fuel source does not change, why is this needed? EPA should include in the rule at most, a one-time testing requirement if the fuel source does not change significantly.

Response: EPA acknowledges the commenters' concerns regarding natural gas sampling costs, and has revised the §98.34 as follows: for natural gas, semiannual sampling and analysis is required.

Commenter Name: Angela Burckhalter
Commenter Affiliation: Oklahoma Independent Petroleum Association (OIPA)
Document Control Number: EPA-HQ-OAR-2008-0508-0386.1
Comment Excerpt Number: 24

Comment: Under Tier 2, EPA proposes that the high heat value of each fuel combusted be measured monthly. If the fuel source does not change, why is this measurement needed? We request EPA include in the rule at most, a one-time testing requirement if the fuel source does not change.

Response: EPA agrees with the commenter and the mandatory monthly fuel sampling and analysis requirements for traditional fossil fuels have been dropped from Tiers 2 and 3. Section 98.34 has been revised to require that natural gas be sampled semiannually. For fuel oil and coal, a representative sampling is required for each fuel lot, i.e., for each shipment or delivery. For other liquid fuels and biogas, quarterly sampling is required. For other solid fuels, excluding municipal solid waste, weekly composite sampling with monthly analysis is required. For other gaseous fuels, the daily sampling requirement has been retained, but only for facilities with existing equipment in place that is capable of providing the data. Otherwise, weekly sampling is required, which may be postponed in favor of monthly sampling until 2011 if new equipment must be purchased or if existing equipment must be upgraded to meet the weekly sampling and analysis requirements.

Commenter Name: Verne Shortell
Commenter Affiliation: NRG Energy, Inc.
Document Control Number: EPA-HQ-OAR-2008-0508-0634.1
Comment Excerpt Number: 3

Comment: Reporting and monitoring rules (40 CFR Part 75) were developed to address the Acid Rain Program allowance trading program, i.e. SO_2 allowances. The rules were developed at a time when emissions trading and markets were in their infancy, and there was little experience with flow monitors. In addition, there are fundamental differences that exist between SO_2 and CO_2 flue gas concentrations. The conservatism, previously acceptable when monitoring SO_2, becomes cost prohibitive under a CO_2 monitoring and allowance trading regime. Consideration should be given to changes of the Part 75 rules prior to carte blanche application to a GHG trading program.
1. Part 75 SO_2 methodology is neither necessary nor appropriate for CO_2. The primary emphasis in the Part 75 monitoring was to track SO_2 emissions from coal-fired power plants. Because there is significant variation in the sulfur content of coal and coal sampling techniques affect the measurement of sulfur content, the rules do not allow data reporting based on anything other than hourly CEMS data. However, it also became quickly apparent that for oil and gas fired units, fuel sampling and measurement was an accurate way to calculate SO_2 emissions for those sources. As a result, optional approaches for SO_2 reporting were allowed. The variation of carbon content in coal is much more similar to the sulfur content in oil, so the variation in carbon content is not as important when measuring and reporting CO_2 emissions. The quantity of coal burned is a financially important parameter, so facilities measure the amount of coal burned accurately. In both cases even if there is hour-to-hour variation, the long-term results should

even out and CO_2 is only a concern over longer periods. Therefore, if a facility can certify coal quantity measurements then it should be allowed to calculate the CO_2 emitted based on carbon content measurements and the amount of fuel burned. In order to completely and accurately track SO_2 emissions via CEMS, the Part 75 rules include a data substitution methodology for hourly data that encourages high monitor data availability. If data are missing, either because a monitor or data acquisition and handling system (DAHS) is down or there is a validation issue, data are substituted on a sliding scale based on monitor data availability [See DCN: EPA-HQ-OAR-2008-0508-0634.1 for Table 1 - Missing Data Procedure for SO_2 CEMS, CO_2 CEMS, Moisture CEMS, Hg CEMS, and diluent (CO_2 or O_2) Monitors for Heat Input Determination provided by the commenter]. As noted above this is appropriate for SO_2 where hourly data could be variable. However, CO_2 hourly variation is not as significant; therefore, data substitution for longer periods could be accomplished by using fuel consumption data.
2. EPA should allow alternative approaches to Part 75 to estimate heat input accurately. Various factors such as CO_2 removed from the flue gas, the upward bias, and drift can lead to inaccurate measurements of CO_2 under Part 75. Under 40 C.F.R. Part 75, Appendix F, heat input is calculated using the unit stack gas flow, percentage of CO_2 and a fuel-specific factor set forth in Appendix F representing the heat content of each fuel (known as an "F Factor"). If CO_2 in the unit's flue gas is removed, a primary variable in the CEMS equation will no longer be reliable. Therefore, additional methods will need to be available in the regulations to determine a unit's hourly and annual heat input. These additional methods could include mass fuel flow measurements and fuel heat content analysis. There is a known upward bias in current stack flow measurement regulations. Under 40 C.F.R. Part 75, a "reference monitor" is introduced each year and compared to an affected unit's stack flow monitor. A side-by-side comparison is performed, and for any resulting difference, a bias adjustment factor must be applied. However, the current rules prescribe that only a positive adjustment factor can be applied. Therefore, if the reference monitor demonstrates a higher level of flow than the affected unit's monitor, then a bias adjustment factor is added into the stack flow equation. If the reference monitor demonstrates a lower level of flow, no bias adjustment can be made. Drift, caused naturally by changing air currents and temperature, also compromises CO_2 CEMS measurements. Though allowable under current regulations, it can lead to additional CO_2 mass emissions error. It is estimated that the combination of measurement methods and data processing techniques can add a positive (high) bias to actual emission levels, perhaps "on the order of two-ten percent". [See DCN: EPA-HQ-OAR-2008-0508-0634.1 for table showing the impact of just a one percent overall high bias on NRG (2008 emissions)]. Note the relative difference between SO_2 and CO_2.

Response: See the Preamble, Section III. C., the Subpart D comment response document volume, and the response to comment EPA-HQ-OAR-2008-0508-0956.1 excerpt 20 for the rationale for using substitute data reported under Part 75.

Under this rulemaking EPA is not revising Part 75 reporting requirements. EPA is keeping GHG monitoring requirements consistent with current monitoring because the Agency does not want to require two sets of data which would add cost and complexity.

Facilities that meet the requirements laid out in §98.33(b) can choose from a number of CO_2 reporting options, including those suggested by the commenter.

Commenter Name: Thomas M. Ward
Commenter Affiliation: Novelis Corporation
Document Control Number: EPA-HQ-OAR-2008-0508-0561.1
Comment Excerpt Number: 4

Comment: Carbon Content Determinations. The complexity of the additional carbon content measurements and heating value measurements will add recordkeeping burdens and sampling and analytical costs that are incommensurate with the small potential increase in GHG emission accuracy that could be obtained. This is especially true for gas and liquid fuels that have relatively constant carbon contents. We propose revising to the proposed rule so that Tier 1 reporting as a default with reporting at the higher tier levels available to facilities as an opt-in effort. Default Tier 1 reporting should apply at the very least to small and medium size facilities. In addition, alternative means for measuring content also need to be addressed in the rule such as in-line measurements by such devices as calorimeters.

Response: See the Preamble, Section II. L., on General Monitoring Requirements for the overall rationale for methodologies required under this rule, and the response to comment EPA-HQ-OAR-2008-0508-0909.1 excerpt 4 and EPA-HQ-OAR-2008-0508-0580 excerpt 10 for the rationale for methodologies required under Subpart C.

EPA has significantly expanded the use of the Tier 2 Calculation Methodology. The 250 mmBtu/hr restriction on the use of Tier 2 has been lifted for units that combust natural gas and distillate oil, in view of the homogeneous nature and low variability in the characteristics of these fuels. However, the 250 mmBtu/hr unit size cutoff remains for units that combust residual oil and solid fossil fuel.

EPA has also relaxed the frequency of the required sampling and analysis. First, the mandatory monthly fuel sampling and analysis requirements for traditional fossil fuels have been dropped from Tiers 2 and 3. Section 98.34 has been revised to require that natural gas be sampled semiannually. For fuel oil and coal, a representative sampling is required for each fuel lot, i.e., for each shipment or delivery. For other liquid fuels and biogas, quarterly sampling is required. For other solid fuels, excluding municipal solid waste, weekly composite sampling with monthly analysis is required. For other gaseous fuels, the daily sampling requirement has been retained, but only for facilities with existing equipment in place that is capable of providing the data. Otherwise, weekly sampling is required, which may be postponed in favor of monthly sampling until 2011 if new equipment must be purchased or if existing equipment must be upgraded to meet the weekly sampling and analysis requirements.

Commenter Name: Edward N. Saccoccia
Commenter Affiliation: Praxair Inc.
Document Control Number: EPA-HQ-OAR-2008-0508-0977.1
Comment Excerpt Number: 6

Comment: The proposed rule requires periodic sampling and analysis of fuels for HHV or carbon content under §98.34(c)(1) and (2) and §98.34(d)(3). The rule implies this sampling and analysis is to be done by the consumer of the fuel, the reporting source. The proposed rule further describes minimum sampling and analysis frequencies for each fuel type. The proposed rule implies a need for characterization of standard commercial fuels to meet calculation method Tier 2 and 3, when, in actuality, the HHV and carbon content of standard fuels are nearly constant values and default values (e.g. Tier 1 calculation method) yield sufficiently accurate emission estimates. Recognizing the objective of the reporting rule is to develop a reasonable estimate of the annual emissions from a source:

1. Standard fuels of commerce (natural gas, LP gas, fuel oils, etc.) that are supplied to multiple consumers are more efficiently characterized by their suppliers than by their consumers.
2. Standard fuels of commerce (excepting coal) have very consistent HHV and carbon contents, requiring much lower characterization frequency. Monthly characterization, as required under §98.34(c)(1) and §98.34(d)(3), of such consistent fuels is costly and does not materially improve the annual estimate of emissions.
3. Process-specific fuel sources (e.g. refinery gas) vary over time, but requiring daily sampling and analysis is very burdensome and costly for a degree of characterization that is intended to yield an annual emission estimate. The characterization of standard fuels of commerce should not be required since default values employed under the Tier 1 calculation method will yield a sufficiently accurate emission estimate (per comments regarding §98.33(b)(1), (3), and (4), above). Characterization of standard fuels of commerce should be optional, at the source's discretion. When a source chooses (or is required) to provide a fuel characterization, the characterization sampling and analysis should be the responsibility of the fuel supplier. Such suppliers should then be required to provide the characterizations to any fuel consumers, upon request. The agency should then accept these characterizations for use under Tier 2 and 3 calculation methods. The characterization frequency of standard fuels of commerce should be reduced to annually. The characterization of process-specific fuels should be reduced to monthly. Alternately, a source should be able to demonstrate that, after a period of required characterization, the variability of the average fuel characteristic (HHV or carbon content) is sufficiently small to justify a reduction in the sampling and analysis burden.

Response: EPA acknowledges the commenter's concerns, and has revised its required sampling and analysis methods. First, the mandatory monthly fuel sampling and analysis requirements for traditional fossil fuels have been dropped from Tiers 2 and 3. Section 98.34 has been revised to require that natural gas be sampled semiannually. For fuel oil and coal, a representative sampling is required for each fuel lot, i.e., for each shipment or delivery. For other liquid fuels and biogas, quarterly sampling is required. For other solid fuels, excluding municipal solid waste, weekly composite sampling with monthly analysis is required. For other gaseous fuels, the daily sampling requirement has been retained, but only for facilities with existing equipment in place that is capable of providing the data. Otherwise, weekly sampling is required, which may be postponed in favor of monthly sampling until 2011 if new equipment must be purchased or if existing equipment must be upgraded to meet the weekly sampling and analysis requirements.

The final rule clarifies that fuel sampling and analysis data provided by the supplier may be used in the emission calculations, and that fuel billing meters may be used to quantify fuel consumption. To simplify the emission calculations in Tiers 2 and 3, averaging of HHV and carbon content data is permitted if these data are obtained at least at the minimum frequency specified in §98.34. If the results of fuel sampling are received monthly or more frequently, the weighted annual average high heat value shall be calculated using Equation C-2b. If the results of fuel sampling are received less frequently than monthly, then the annual average HHV shall be calculated using the arithmetic average HHV for all valid samples for the year. However, regardless of the sampling frequency, the owner or operator must use the results of all available valid fuel analyses in the emissions calculations.

EPA has not required fuel suppliers to provide HHV and carbon content data to facilities, as it is the source's responsibility to determine emissions. Fuel suppliers have their own reporting requirements in other subparts. Additionally, it is the role of private sector transactions to specificy the terms of the information provided through fuel purchase contracts.

Subpart KK, Suppliers of Coal, has not been included in this final rule. Subpart MM, Suppliers of Petroleum Products, and Subpart NN, Suppliers of Natural Gas, provide upstream reporters with the option of using default HHV and carbon contents or site specific sampling. EPA has not required fuel suppliers to provide HHV data to facilities, as provision of this type of information is typically addressed in private sector purchase contracts.

Commenter Name: None
Commenter Affiliation: Vectren Corporation
Document Control Number: EPA-HQ-OAR-2008-0508-0597
Comment Excerpt Number: 6

Comment: Vectren supports the limiting provision in section 98.34(d)(1) which states that "All oil and gas flow meters (except for gas billing meters) shall be calibrated prior to the first year for which GHG emissions are reported under this part..." And Vectren strongly urges EPA insert a similar parenthetical to exclude gas billing meters from annual calibration, as follows: "Fuel flow meters (except for gas billing meters) shall be recalibrated either annually or at the minimum frequency specified by the manufacturer."

Response: EPA acknowledges the concerns of the commenters. Section 98.34(d)(1) of the final rule has been clarified to exempt fuel billing meters from the calibration requirement, "provided that the supplier and the unit(s) combusting the fuel do not have any common owners and are not owned by subsidiaries or affiliates of the same company."

Commenter Name: Thomas M. Ward
Commenter Affiliation: Novelis Corporation
Document Control Number: EPA-HQ-OAR-2008-0508-0561.1
Comment Excerpt Number: 7

Comment: Small Emission-Unit Data Reporting Requirements Should be Revised to Reduce Fuel Monitoring- Requirements Section 98.36(c)(1) of the proposed rule restricts aggregation of small units to a group "not to exceed 250 mmBTU/hr". Novelis believes that this aggregation cutoff is arbitrary and unnecessary for reporting purposes. In addition, the requirement makes no distinction for fuel type, such as natural gas vs. coal, and the monitoring issues that differ by fuel type. As proposed, this provision would require the installation of fuel monitoring equipment at many natural gas-fired manufacturing facilities resulting in no improvement in GHG data quality. Many affected industrial facilities that use natural gas for process combustion and building heat use more than 250 mmBTU/hr. These facilities may have numerous (10, 20 or more) stationary combustion units of different types and sizes, but have only a single monitor (gas meter) where the amount of natural gas is metered by the natural gas supplier or utility. The proposed rule would require these facilities to somehow subdivide the natural gas combustion units into groups that use less than 250 mmBTU/hr, and then install and maintain additional (internal) gas meters for the sole purpose of GHG emissions reporting. As written, the rule unreasonably complicates a process where existing information could be used without the increased costs. Specifically, existing site-wide gas meters at industrial facilities are already properly maintained by the utility as a point of commercial sale. In addition, the fuel content of natural gas is very consistent, and the fuel combustion efficiency of natural gas-fired processes is maintained for emission control purposes. Therefore, adding additional meters to create subgroups of combustion units less than 250 mmBTU/hr adds no value at considerably increased cost in capital, monitoring and recordkeeping. Novelis objects to this provision and recommends that the final rule allow aggregation of small units up to any total mmBTU/hr usage as long as all of the fuel used by the aggregated units is metered or measured at a single point while retaining the ability to use Tier 1 or Tier 2 reporting. This still serves the EPA rule's objectives.

Response: For units that use Tiers 1, 2, and 3 to calculate CO_2 mass emissions, the cumulative 250 mmBtu/hr heat input capacity limit on the aggregation of units into a group has been dropped. Rather, the 250 mmBtu/hr restriction applies only to the individual units in the group. Therefore, for reporting purposes, individual units with maximum rated heat input capacities of 250 mmBtu/hr or less may be aggregated without limit into a single group, provided that the Tier 4 methodology is not required for any of the units, and all units in the group use the same tier for any common fuel(s) that they combust. Units with maximum rated heat inputs greater than 250 mmBtu/hr must report as individual units, unless they burn the same type of fuel (oil or gas) provided by a common pipe or supply line; in that case, the owner or operator may opt to use the highest tier required for a grouped unit for the calculation method with the common pipe reporting provisions in §98.36. Units using Tier 4 must report as individual units unless they share a monitored common stack; in that case, the common stack reporting provisions of §98.36 may be used.

Commenter Name: Lorraine Krupa Gershman
Commenter Affiliation: American Chemistry Council (ACC)
Document Control Number: EPA-HQ-OAR-2008-0508-0423.2
Comment Excerpt Number: 63

Comment: Further, in §98.34(d)(1,) a facility might be purchasing different components from different manufacturers, e.g. the dP cell manufacturer might differ from the orifice manufacturer. It might, therefore, be difficult to follow the manufacturer's recommendations because different manufacturers might have recommendations in conflict with each other. Also in §98.34(d)(1), some meter warranties may be voided if an attempt is made to calibrate them. In such a situation, EPA should allow for a facility to follow the manufacturer's recommendations or specifications. Based on all of the above constraints and concerns, ACC recommends that in §98.34(d)(1), EPA require meter calibration at the lesser of the manufacturer's recommendations or annually or, alternatively, to calibrate on an alternate frequency determined to be appropriate through operating experience for the meter or based on other engineering analyses. This will address facilities whose flow measurement device manufacturers do not recommend periodic calibration and will also address other concerns noted in the proposed frequency.

Response: EPA believes that the structure of the final rule mirrors this suggestion to a large extent. In §98.34 for on-going QA, the Agency requires either a biannual (i.e., once every two years) recalibration or at the minimum frequency specified by the manufacturer. However for orifice, nozzle, and venturi meters, the transmitters will be required to recalibrate in-situ at least annually, with a PEI performed at least once every three years. For continuously operating units and processes, the recalibratons and, if necessary, the PEIs, may be postponed until the next scheduled maintenance outage.

Commenter Name: Paul R. Pike
Commenter Affiliation: Ameren Corporation
Document Control Number: EPA-HQ-OAR-2008-0508-0487.1
Comment Excerpt Number: 12

Comment: Under §98.36(b) and §98.46(a), EPA proposes to require unit level reporting of various pieces of information for Subpart C combustion sources, and for ARP units. Although most of the information specified in §98.36(b) is not burdensome to report, the data required under (b)(5) would be for some units. Proposed §98.36(b)(5) would require the reporting of calculated CO_2, CH_4, and N_2O data for each fuel type combusted at the unit. Units using continuous monitoring methods, like CO_2/O_2 CEMS and volumetric flow monitors (to calculate heat input) generally do not employ instrumentation to record when a different fuel is being combusted. For example, a coal-fired unit that uses oil to startup would monitor CO_2/O_2 and volumetric flow all the way through the startup process and past the point when coal enters the boiler without any recordation of when the change in fuel took place. Similarly, some oil and gas-fired units may switch between the two fuels, or even co-fire oil and gas, without recording which fuel or fuels was responsible for the emissions and flow. For such units, it simply is not possible to provide estimates of emissions by fuel type without addition of what might be complicated, expensive, and otherwise unnecessary instrumentation. EPA should remove the provision or limit its application to units that already have the instrumentation or other means to make the calculation. If EPA retains the requirement, the Agency must describe why the information is needed, estimate the costs of gathering this information, and provide sufficient time for installation of equipment.

Response: EPA acknowledges the commenter's concerns, and has addressed this issue in the final rule. Section 98.36 of the final rule states that, for Tier 4 units, the annual CO_2 emissions will be reported for all fuels combined, and that any biogenic CO_2 emissions will also be reported separately. It also states that CH_4 and N_2O emissions are to be reported for each type of fuel combusted, calculated in accordance with §98.33. In §98.33, EPA has specified that reporters using Tier 4 are to use the best available estimates of the annual heat input from each type of fuel combusted in the unit during the reporting year, excluding fuel used only for startup or ignition. This can be from CEMS data or engineering calculations. Using this data they are to calculate CH_4 and N_2O emissions for each fuel type.

In revising the final version of the rule, EPA has also added to §98.36 to define data reporting requirements for units subject to Part 75, which requires total emissions by unit, not by fuel. EPA believes that these provisions in the final rule effectively address the concerns of the commenter.

Commenter Name: Rich Raiders
Commenter Affiliation: Arkema Inc.
Document Control Number: EPA-HQ-OAR-2008-0508-0511.1
Comment Excerpt Number: 41

Comment: Subpart C also requires pipeline gas meter calibrations. Arkema is not familiar with any current requirement for users to calibrate gas meters. Typically, the supplier manages gas flow meter calibration, and the customers are typically unaware of the pipeline companies' calibration procedures. EPA should allow reporters to rely on pipeline-certified natural gas flow measurement without any requirement to calibrate flow meters used for supplier billing purposes. Natural gas flow meters used in-process to determine local gas flows should only be calibrated at manufacturer specified intervals, if at all. If a reporter elects to purchase and install natural gas flow meters that are manufactured to operate for several years between calibrations, EPA should not impose unnecessary calibration schedules for known reliable meters.

Response: EPA acknowledges the concerns of the commenters. Section 98.34 of the final rule has been clarified to exempt fuel billing meters from the calibration requirement, "provided that the supplier and the unit(s) combusting the fuel do not have any common owners and are not owned by subsidiaries or affiliates of the same company."

Commenter Name: Lorraine Krupa Gershman
Commenter Affiliation: American Chemistry Council (ACC)
Document Control Number: EPA-HQ-OAR-2008-0508-0423.2
Comment Excerpt Number: 60

Comment: Sections 98.34(c) and 98.34(d)(3) require routine measurement of the HHV and carbon content of fuels, respectively. The reporter should be allowed to use fuel specifications that include, but are not limited to, regulatory requirements, data provided by fuel suppliers, and specifications set by the reporter to determine HHV and carbon content. The frequency for determining HHV or carbon content from data obtained from a fuel supplier should be the same frequency for obtaining the data from the supplier. Also similar to other Clean Air Act rules, the final rule should include an option to decrease the frequency of sampling to annually if several consecutive measurements show minimum variation in the HHV or carbon contents.

Response: EPA acknowledges the commenter's concerns, and has revised its required sampling and analysis methods. First, the mandatory monthly fuel sampling and analysis requirements for traditional fossil fuels have been dropped from Tiers 2 and 3. Section 98.34 has been revised to require that natural gas be sampled semiannually. For fuel oil and coal, a representative sampling is required for each fuel lot, i.e., for each shipment or delivery. For other liquid fuels and biogas, quarterly sampling is required. For other solid fuels, excluding municipal solid waste, weekly composite sampling with monthly analysis is required. For other gaseous fuels, the daily sampling requirement has been retained, but only for facilities with existing equipment in place that is capable of providing the data. Otherwise, weekly sampling is required, which may be postponed in favor of monthly sampling until 2011 if new equipment must be purchased or if existing equipment must be upgraded to meet the weekly sampling and analysis requirements.

The final rule clarifies that fuel sampling and analysis data provided by the supplier may be used in the emission calculations, and that fuel billing meters may be used to quantify fuel consumption. To simplify the emission calculations in Tiers 2 and 3, averaging of HHV and carbon content data is permitted if these data are obtained at least at the minimum frequency specified in §98.34. If the results of fuel sampling are received monthly or more frequently, the weighted annual average high heat value shall be calculated using Equation C-2b. If the results of fuel sampling are received less frequently than monthly, then the annual average HHV shall be calculated using the arithmetic average HHV for all valid samples for the year. However, regardless of the sampling frequency, the owner or operator must use the results of all available valid fuel analyses in the emissions calculations.

The Agency is not opposed to alternative approaches for sampling frequency options, such as decreasing sampling in certain cases with consistently homogenous results as described by the commenter. However, the commenter did not provide any supplementary information, proposed rule language, or cost analysis to explain how this proposed methodology could be implemented. In view of this, EPA has not incorporated the commenter's suggested approach into the final rule, but is willing to consider it in a future rulemaking, if the necessary technical details of the method are provided for Agency review.

Commenter Name: Lauren E. Freeman
Commenter Affiliation: Hunton & Williams LLP
Document Control Number: EPA-HQ-OAR-2008-0508-0493.1
Comment Excerpt Number: 25

Comment: Proposed §§98.44 - 98.46 are largely superfluous in that they simply repeat requirements that are already set out either in Part 75 or in Subpart C. For example, if a source is using CO_2 data reported under Part 75 to report under this program, it is not necessary to separately specify that those data must be quality assured under Part 75 or that the missing data provisions of Part 75 must be followed. The CO_2 data that were reported under Part 75 will be either Part 75 quality-assured data or data estimated using Part 75 missing data procedures. It also is not necessary to require in this rule that such units "continue to monitor and report" CO_2 emissions under Part 75, as required under proposed §98.43, or to specify under this subpart the meaning of terms, as stated in proposed §98.48. Repeating requirements that are already set out in Part 75 or in Subpart A to Part 98 is unnecessary, confusing, and inappropriate.

Response: EPA has included rule language that may appear to be redundant in order to provide clarity that requirements under Part 75 continue to apply to Part 98 reporters.

Commenter Name: Sarah B. King
Commenter Affiliation: DuPont Company
Document Control Number: EPA-HQ-OAR-2008-0508-0604.1
Comment Excerpt Number: 27

Comment: Regarding §98.34(c)(1) and (d)(3), the composition of natural gas does not change often enough to warrant monthly sampling. DuPont recommends annual analysis at most for natural gas. End user sampling and testing of fuels should be deleted to reduce the excessive burden of each facility needing to sample and analyze the fuel when it could be more efficiently sampled and analyzed only once by the supplier instead. Additionally, the sampling frequency should be yearly or whenever the supplier changes the source of the fuel such that the fuel composition may be likely to change.

Response: EPA acknowledges the commenters' concerns regarding natural gas sampling costs, and has revised the §98.34 as follows: for natural gas, semiannual sampling and analysis is required.

Commenter Name: Sarah B. King
Commenter Affiliation: DuPont Company
Document Control Number: EPA-HQ-OAR-2008-0508-0604.1
Comment Excerpt Number: 28

Comment: Sections 98.34(c) and 98.34(d)(3) require routine measurement of the HHV and carbon content of fuels, respectively. The reporter should be allowed to use data provided by fuel suppliers to determine HHV and carbon content. Also similar to other Clean Air Act rules, the rule should include an option to decrease the frequency of sampling to annually if several consecutive measurements show minimum variation in the HHV or carbon contents. EPA should specify that analysis is to be on an "As-Received" basis for solid fuels.

Response: EPA acknowledges the commenter's concerns, and has revised its required sampling and analysis methods. First, the mandatory monthly fuel sampling and analysis requirements for traditional fossil fuels have been dropped from Tiers 2 and 3. Section 98.34 has been revised to require that natural gas be sampled semiannually. For fuel oil and coal, a representative sampling is required for each fuel lot, i.e., for each shipment or delivery. For other liquid fuels and biogas, quarterly sampling is required. For other solid fuels, excluding municipal solid waste, weekly composite sampling with monthly analysis is required. For other gaseous fuels, the daily sampling requirement has been retained, but only for facilities with existing equipment in place that is capable of providing the data. Otherwise, weekly sampling is required, which may be postponed in favor of monthly sampling until 2011 if new equipment must be purchased or if existing equipment must be upgraded to meet the weekly sampling and analysis requirements.

The final rule clarifies that fuel sampling and analysis data provided by the supplier may be used in the emission calculations, and that fuel billing meters may be used to quantify fuel consumption. To simplify the emission calculations in Tiers 2 and 3, averaging of HHV and carbon content data is permitted if these data are obtained at least at the minimum frequency specified in §98.34. If the results of fuel sampling are received monthly or more frequently, the weighted annual average high heat value shall be calculated using Equation C-2b. If the results of fuel sampling are received less frequently than monthly, then the annual average HHV shall be calculated using the arithmetic average HHV for all valid samples for the year. However, regardless of the sampling frequency, the owner or operator must use the results of all available valid fuel analyses in the emissions calculations.

Commenter Name: Sarah B. King
Commenter Affiliation: DuPont Company
Document Control Number: EPA-HQ-OAR-2008-0508-0604.1
Comment Excerpt Number: 29

Comment: Regarding §98.34(d)(3), combustion of gaseous fuels other than natural gas (e.g., refinery gas, or process gas) needs to use Tier 3 unless a CEMS is used for Tier 4. This paragraph indicates (and Preamble p 16484 also stipulates) that daily sampling and analysis is required to determine carbon content and molecular weight of the fuel. The Preamble notes that "The daily fuel sampling requirement for units that combust "other" gaseous fuels would likely not be overly burdensome, because the types of facilities that burn these fuels are likely to have equipment (e.g., on-line gas chromatographs) to continuously monitor the fuels' characteristics in order to optimize process operation." While this is the case for some particular offgas streams, it is definitely not the case for all process gases, and those with monitoring might require considerable cost to upgrade for this purpose. This requirement could impose a significant and unjustified cost on some facilities that wouldn't otherwise be required to use CEMs. If such sampling and analytical equipment is not installed, it should be acceptable to use typical analytical or engineering data to determine the process gas composition. Additionally, if a process gas stream contains less than 25% carbon by weight as demonstrated by engineering or model analysis, that initial demonstrated value should be considered adequate for ongoing emissions determinations. CO_2 emissions resulting from such low-carbon gas streams are generally not material as these streams are typically not large volume. Moreover, following the de minimis concepts explained above, if the process gas stream does not contain significant carbon content (< 10% by weight), there should be no need for any reporting for those process gas streams providing documentation is retained supporting that position.

Response: See the response to excerpt 28 from the same letter, EPA-HQ-OAR-2008-0508-0604 (directly preceding).

Commenter Name: Sarah B. King
Commenter Affiliation: DuPont Company
Document Control Number: EPA-HQ-OAR-2008-0508-0604.1
Comment Excerpt Number: 30

Comment: In §98.34, EPA does not provide a specified recommended methodology for measuring solid fuels, but rather relies on company records. Requiring measurement of the fuel rate instead of allowing calculation would be especially burdensome and unnecessarily costly, and would require the installation of weighing equipment which simply cannot be installed in some cases due to required equipment configurations. Some sites currently calculate the amount of solid fuel combusted based on, for example in the case of a boiler, the amount of steam generated and the boiler efficiency. For example, the Tier 2 methodology for MSW fired units allows for use of boiler steam output and the maximum rated heat input to design steam output ratio to determine heat input. A similar approach could also be used for other solid fuel fired units. Similarly, in cases where byproduct fuels are fired or co-fired, the covered entity should have latitude to utilize any methods appropriate for the unit that provide representative determination of CO_2 emissions. EPA should continue to allow such engineering calculations for solid fuel flow rate. Providing flexibility in fuel consumption determination methodology will decrease the cost of the reporting program with an insignificant impact on overall emissions accounting accuracy. It is assumed that this is EPA's intention based on the reference to relying on company records.

Response: See the response to excerpt 28 from the same letter, EPA-HQ-OAR-2008-0508-0604 (preceding).

Commenter Name: Ron Downey
Commenter Affiliation: LWB Refractories
Document Control Number: EPA-HQ-OAR-2008-0508-0719.1
Comment Excerpt Number: 33

Comment: Sampling Requirements for Tier 2 and Tier 3 Facilities: The Preamble, 74 Fed. Reg. at 16,484, and Table 8 in the Technical Support Documentation indicate that 40 CFR Part 98.34(d)(3) requires a Tier 3 facility using solid fuel to sample weekly and composite weekly sample results into a monthly carbon content value that is reported. This is consistent with the sampling requirements for Tier 2 facilities. See 40 C.F.R. 98.34(c)(2). However, 40 C.F.R. 98.7 incorporates by reference several ASTM standards, including ASTM D2234 (Standard Practice for Collection of a Gross Sample of Coal). To the extent that the specific sampling procedures in 40 CFR Part 98.33(a)(3) conflict with the general reference to ASTM D2234, 40 C.F.R. Part 98.33(a)(3) should control. The Proposed Rule should clearly state that the incorporation by reference of ASTM D2234 at 40 C.F.R. 98.7 does not supersede the sampling frequency requirements in 40 C.F.R. 98.33(a)(3). Adherence to the sampling requirements in 40 C.F.R. 98.33(a)(3) will provide consistent sampling among Tier 3 facilities. ASTM D2234, in contrast, allows sources to determine their own sampling frequency.

Response: EPA has revised §98.34 to clarify that only the methods listed in that section may be used for fuel sampling and analysis for Tiers 2 and 3, regardless of any other methods that are incorporated in §98.7. ASTM D2234, though incorporated by reference at §98.7, is not listed in §98.34, and therefore may not be used for the purposes of Subpart C.

Commenter Name: Ron Downey
Commenter Affiliation: LWB Refractories
Document Control Number: EPA-HQ-OAR-2008-0508-0719.1
Comment Excerpt Number: 34

Comment: Determining High Heat Values: The Preamble provides that Tier 1 and Tier 2 facilities can rely on fuel supply vendors to supply the high heat value for the fuel combusted.

Preamble at V.C.3a. 40 C.F.R. 98.33(a)(1) and (2) should be revised to reflect that high heat value measurements for fuel combusted in a Tier 1 and Tier 2 facilities may be obtained from the fuel supplier.

Response: The final rule clarifies that fuel sampling and analysis data provided by the supplier may be used in the emission calculations, and that fuel billing meters may be used to quantify fuel consumption. To simplify the emission calculations in Tiers 2 and 3, averaging of HHV and carbon content data is permitted if these data are obtained at least at the minimum frequency specified in §98.34. If the results of fuel sampling are received monthly or more frequently, the weighted annual average high heat value shall be calculated using Equation C-2b. If the results of fuel sampling are received less frequently than monthly, then the annual average HHV shall be calculated using the arithmetic average HHV for all valid samples for the year. However, regardless of the sampling frequency, the owner or operator must use the results of all available valid fuel analyses in the emissions calculations.

Commenter Name: See Table 5
Commenter Affiliation:
Document Control Number: EPA-HQ-OAR-2008-0508-0480.1
Comment Excerpt Number: 37

Comment: Accurate fuel measurement is inherent to natural gas transmission and storage operations, and expertise within this industry for natural gas fuel rate measurement is unsurpassed. For fuel metering, §98.34(d)(1) requires operators to follow methods in §98.7 or vendor defined calibration procedures. Within the natural gas industry, flow measurement quality control and quality assurance procedures have been developed and refined over years, and common practices are in place to ensure metering QA/QC. §98.34(d)(1) should be revised to provide the flexibility to use accepted operator-defined practices for fuel flow meter calibration and other QA/QC measures. This ensures that natural gas operators can continue to use accepted methodologies to ensure accurate fuel measurement.

Response: EPA believes that the language in §98.34 is clear, offers substantial flexibility, and does not require the revision suggested by the commenter. EPA defines acceptable test methods as those listed in §98.7 or the calibration procedures specified by the flow meter manufacturer.

Commenter Name: Robert Rouse
Commenter Affiliation: The Dow Chemical Company
Document Control Number: EPA-HQ-OAR-2008-0508-0533.1
Comment Excerpt Number: 24

Comment: EPA Should Revise the Requirements for Fuel Sampling for Natural Gas. Referencing 98.34(c)(1) and (d)(3), the composition of natural gas does not change often enough to warrant monthly sampling. Dow suggests that EPA consider semi-annual sampling at most for natural gas. Requiring these fuels to be sampled twice per year would align with many custom fuel sampling schedules for determining the sulfur content of natural gas that are driven by other EPA regulations such as NSPS Subpart GG. In addition, Dow suggests that EPA consider limiting the source sampling and testing of fuels, including pipeline natural gas supplies, to reduce the excessive burden of each facility needing to sample and analyze the fuel when it could be more efficiently sampled and analyzed by the supplier instead. The sampling frequency should be semi-annual or whenever the supplier changes the source of the fuel such that the fuel composition may be likely to change. These fuels will not change so much in composition from month to month. Therefore, the monthly sampling requirement is overly burdensome, and reducing the frequency will not impact the total GHG emissions inventory. Dow Suggests that EPA Allow the Use of Fuel Supplier Information for Tier 2 or 3 Methodologies. EPA requested comment on integrating fuel supplier requirement for HHVs and carbon content for Tier 1 and Tier 2 methodologies. Dow comments that information provided by the fuel supplier should be allowed to be used in Tier 2 and 3 methodologies. This method of allowing the fuel supplier to provide this information instead of the fuel users eliminates unnecessary duplication of analysis of the same fuel by multiple users. For example, one fuel supplier might supply dozens or even more units within an industrial area, and requiring the fuel supplier to provide the data would reduce the number of required analyses correspondingly. In addition, when making this change, EPA should then alter the requirements in 98.34(c) and (d) such that operators of stationary combustion devices do not need to obtain fuel analytical data when it is provided by the fuel supplier. Dow Suggests Revisions to the Requirements for Daily Sampling of Process Gas to Determine the Carbon Content. In 98.34(d)(3), facilities combusting process gas should be provided with an option to perform a statistical analysis to determine a sample and analytical frequency that is less often than daily based on the potential for variations in process gas composition. Requiring daily sampling for all process fuels may be unnecessary and is burdensome to the plant sites. At a minimum, facilities should be allowed the option of initially sampling monthly and then using a different frequency if warranted by a statistical analysis. In addition, sampling systems may not currently be present on all process gas/fuel lines. EPA's final rule should allow additional time to install all required sample taps or locations that are required to collect the samples for carbon analysis, molecular weight determinations, and higher heating value. In some cases, it may be necessary to take a combustion unit out of service in order to make these installations. Dow comments that owner/operators should have until January 1, 2011 to make these installations, and that the rule should have a mechanism for the owner/operator to request additional time on a case-by-case basis, if needed. GHG emissions can still be determined to a high degree of accuracy by using process knowledge and engineering calculations for the reporting year 2010 in these cases. EPA Should Adjust the Requirements for Periodic and Initial Calibration of Gas Flow Meters. In 98.34(d)(1), some flow meters may not be calibrated without shutting down the process. For example, in some cases, an orifice plate must be pulled out of the line to do a complete calibration. This might be part of manufacturer's recommendations as a part of calibration recommendations. It would not be practical to perform this yearly because equipment may not be out of service on a frequency of more than one time in every several years. The annual calibration should be limited to no more than would be required by Part 75 (electronic transmitter calibration) less the visual inspection every three years. In addition, for the reasons cited above regarding possible unit shutdown for a full calibration per manufacturer's recommendations, it may not be practical or possible to complete all required calibrations between now and January 1, 2010. Dow recommends that EPA allow owners/operators until the next scheduled shutdown for the initial calibration, if it requires a process unit shutdown. Therefore, Dow recommends that in 98.34(d)(1), EPA require meter calibration at the lesser frequency of the manufacturer's recommendations or annually rather than the greater of or, alternatively, to calibrate on an alternate frequency determined to be appropriate through operating experience for the meter or based on other engineering analyses. This will address facilities whose flow measurement device manufacturers do not recommend periodic calibration and will also address other concerns noted in the proposed frequency. EPA Should Adjust the Requirements for Measuring the Carbon Content of Solid Fuel. EPA does not provide a specified recommended methodology for measuring solid fuels in 98.34. Requiring measurement of the fuel rate instead of allowing calculation would be especially burdensome and unnecessarily costly, and would require the installation of weighing equipment. Some sites currently calculate the amount of solid fuel combusted based on, for example in the case of a boiler, the amount of steam generated each month and the boiler efficiency. EPA should continue to allow such engineering calculations for solid fuel flow rate.

Response: EPA acknowledges the commenter's concerns, and has revised its required sampling and analysis methods. First, the mandatory monthly fuel sampling and analysis requirements for traditional fossil fuels have been dropped from Tiers 2 and 3. Section 98.34 has been revised to require that natural gas be sampled semiannually. For fuel oil and coal, a representative sampling is required for each fuel lot, i.e., for each shipment or delivery. For other liquid fuels and biogas, quarterly sampling is required. For other solid fuels, excluding municipal solid waste, weekly composite sampling with monthly analysis is required. For other gaseous fuels, the daily sampling requirement has been retained, but only for facilities with existing equipment in place that is capable of providing the data. Otherwise, weekly sampling is required, which may be postponed in favor of monthly sampling until 2011 if new equipment must be purchased or if existing equipment must be upgraded to meet the weekly sampling and analysis requirements.

The final rule clarifies that fuel sampling and analysis data provided by the supplier may be used in the emission calculations, and that fuel billing meters may be used to quantify fuel consumption. To simplify the emission calculations in Tiers 2 and 3, averaging of HHV and carbon content data is permitted if these data are obtained at least at the minimum frequency specified in §98.34. If the results of fuel sampling are received monthly or more frequently, the weighted annual average high heat value shall be calculated using Equation C-2b. If the results of fuel sampling are received less frequently than monthly, then the annual average HHV shall be calculated using the arithmetic average HHV for all valid samples for the year. However, regardless of the sampling frequency, the owner or operator must use the results of all available valid fuel analyses in the emissions calculations.

Section 98.34 of the final rule clarifies that for units and processes that operate continuously with infrequent outages and use an orifice, nozzle, or venturi meter, the owner or operator may postpone the initial calibration or PEI (as applicable) until the next scheduled maintenance outage, and may similarly postpone the subsequent recalibrations and PEIs. In §98.34 for on-going QA, the Agency requires either a biannual (i.e., once every two years) recalibration or at the minimum frequency specified by the manufacturer. However for orifice, nozzle, and venturi meters, the transmitters will be required to recalibrate in-situ at least annually, with a PEI performed at least once every three years.

Also, EPA has extended the use of steam production and combustion unit efficiency to calculate CO_2 emissions to other solid fuels in addition to municipal solid waste. These parameters may also be used to quantify the amount of biomass combusted in a unit.

Commenter Name: See Table 5
Commenter Affiliation:
Document Control Number: EPA-HQ-OAR-2008-0508-0480.1
Comment Excerpt Number: 39

Comment: Gas measurement and analysis methods continue to be revised and refined, and it is likely that additional consensus methods are available but have not been specifically identified to date. The process for accepting alternative methods into a final rule can be burdensome, time consuming, and cumbersome for operators and EPA. Thus, a streamlined approach is warranted to accept other consensus standards. To address ongoing improvements and evolution in gas measurement methods, INGAA recommends that §98.34 add a provision that indicates that consensus methods not listed in §98.7 but authored by organizations with methods already listed in §98.7 be allowed for fuel flow, fuel carbon, and heating value analysis. In addition, EPA should indicate that other methods accepted by the Administrator are also acceptable. To facilitate approval under this authority, EPA should devise an approach (i.e., expert review group) for expedited review and approval of additional methods that become available or are identified.

Response: EPA disagrees with commenter's request to allow sources to determine the best measurements to use, in order to ensure that consistent data is reported under this rule. EPA has, however, expanded the use of the four tier system to be more significantly more flexible. See §98.33. EPA does not believe that it is appropriate to include consensus methods not yet reviewed and approved by EPA in this rule but will endeavor to expedite review of additional methods which become available.

Commenter Name: Patrick J. Nugent
Commenter Affiliation: Texas Pipeline Association (TPA)
Document Control Number: EPA-HQ-OAR-2008-0508-0460.1
Comment Excerpt Number: 24

Comment: The monthly carbon content determination requirement in proposed §98.3-4(03) should be deleted. Proposed §98.34(dX3) would provide that the carbon content of certain fuels be determined monthly regardless of whether new fuel has been added to the tank. That requirement should be eliminated or modified to provide that regulated entities should not be required to resample tanks on a monthly basis if no additional fuel was added since the last sample. The carbon content of the fuel should not change if additional fuel has not been added.

Response: Section 98.34 has been revised to require that natural gas be sampled semiannually and to require a representative sampling for each fuel lot (i.e., for each shipment or delivery) for fuel oil and coal. For other liquid fuels and biogas, quarterly sampling is required. For other solid fuels, excluding municipal solid waste, weekly composite sampling with monthly analysis is required. For other gaseous fuels, the daily sampling requirement has been retained, but only for facilities with existing equipment in place that is capable of providing the data. Otherwise, weekly sampling is required, which may be postponed in favor of monthly sampling until 2011 if new equipment must be purchased or if existing equipment must be upgraded to meet the weekly sampling and analysis requirements.

The final rule clarifies that fuel sampling and analysis data provided by the supplier may be used in the emission calculations, and that fuel billing meters may be used to quantify fuel consumption. To simplify the emission calculations in Tiers 2 and 3, averaging of HHV and carbon content data is permitted if these data are obtained at least at the minimum frequency specified in §98.34, but less frequently than monthly (see Equation C-2b). However, regardless of the sampling frequency, the owner or operator must use the results of all available valid fuel analyses in the emissions calculations.

Commenter Name: Gregory A. Wilkins
Commenter Affiliation: Marathon Oil Corporation
Document Control Number: EPA-HQ-OAR-2008-0508-0712.1
Comment Excerpt Number: 49

Comment: Marathon opposes the current quality assurance and calibration requirements for flow meters used to obtain daily readings of fuel gas. If the quality control failed when calibrating a flow meter, it may require an inspection of the orifice plate of the meter. An inspection (and hence removal) of this plate could require part of a facility to be shut down. Marathon proposes language stating that due to any malfunctions, quality, or calibration issues, inspections, replacements, and calibrations of flow meters that cannot he done on-line can be delayed until the next scheduled shut down. Currently EPA states that annual calibration or manufacturer specified calibration is required. This may not be feasible for the reasons stated above. Additionally, Marathon proposes that if a critical meter malfunctions and cannot be repaired while on-line, other meters or engineering estimates should be allowed in this situation as long as is necessary (until the meter is replaced or repaired) as this rule isn't intended to affect operations. There should be no mandated time for repair or replacement of this equipment as there are many safety concerns with making repairs while equipment is running. Additionally, shutting down and starting up equipment for compliance with this rule would actually create more GHG emissions. The rule should state that the equipment should be replaced or repaired at the next planned shut-down.

Response: EPA acknowledges the concerns of the commenters. Section 98.34 of the final rule clarifies that for units and processes with orifice, nozzle, or venturi meters that operate continuously with infrequent outages, the owner or operator may postpone the initial calibration or PEI (as applicable) until the next scheduled maintenance outage, and may similarly postpone the subsequent recalibrations and PEIs.

Commenter Name: Gregory A. Wilkins
Commenter Affiliation: Marathon Oil Corporation
Document Control Number: EPA-HQ-OAR-2008-0508-0712.1
Comment Excerpt Number: 52

Comment: Marathon supports the use of common pipe sampling if this final rule does require direct sampling of fuel gas for Tier 3. The common pipe method allows a facility to combine emission estimates for multiple units as a common pipe configuration if a common fuel source fed those multiple units and was metered and measured at the common source. This will simplify emission estimates and monitoring and metering requirements for many facilities. By using a common pipe for sampling, our facilities can reduce samples taken and still maintain accurate estimations. Marathon interprets this rule to also mean that while a common sample may be taken at the fuel drum, flow meters at individual combustion units sharing a common source can be used to determine individual flow and hence emissions. Marathon requests clarification be given in the regulatory language to address this as an option.

Response: EPA has revised §98.36 to clarify that emissions may be combined for units served by the common supply line, provided that the total amount of fuel combusted by the units is accurately measured at the common pipe or supply line using a calibrated fuel flow meter. In addition, EPA has significantly revised §98.34, simplifying sampling and analysis requirements.

Commenter Name: Karen St. John
Commenter Affiliation: BP America Inc. (BP)
Document Control Number: EPA-HQ-OAR-2008-0508-0631.1
Comment Excerpt Number: 61

Comment: Where the Section 98.34 Tier 3 Calculation Methodology is used, EPA has required reporters determine the carbon content of natural gas, biogas, liquid fuels, and solids fuels monthly and of other gaseous fuels such as refinery gas and process gas on a daily basis. For many refinery operations, the carbon content of gas streams does not vary significantly enough to warrant daily determination. EPA should revise the requirement in Section 98.34(d)(3) to specify the reporter must determine the content of gaseous fuels monthly. Daily sampling is excessive for fuels that are fairly stable in composition. The natural gas factor in Table C-1 should be used, or where the gas stream does fluctuate with operational changes, allow the reporter to determine a sampling frequency that is consistent with the variability of the stream.

Response: In preparation of the final rule, EPA has significantly revised §98.34 concerning sampling and analysis requirements. Section 98.34 has been revised to require that natural gas be sampled semiannually and biogas be sampled quarterly. For other gaseous fuels, the daily sampling requirement has been retained, but only for facilities with existing equipment in place that is capable of providing the data. Otherwise, weekly sampling is required, which may be postponed in favor of monthly sampling until 2011 if new equipment must be purchased or if existing equipment must be upgraded to meet the weekly sampling and analysis requirements.

Commenter Name: Karen St. John
Commenter Affiliation: BP America Inc. (BP)
Document Control Number: EPA-HQ-OAR-2008-0508-0631.1
Comment Excerpt Number: 62

Comment: Calibrated flow meters are not addressed for a Tier 1 or Tier 2 calculation approach. If using Tiers 1 or 2, rated horsepower/operating hours etc should be acceptable as legitimate "company records to quantify fuel consumption." Note that the equation definitions for Tiers 1 and 2 indicate fuel flow, but do not use the term "company records" and hence, the inconsistency is vague and confusing. BP is assuming that Tiers 1 and 2 do not require fuel meters, and that the use of company records includes estimation methods as outlined in the API Compendium, based on operating hours and ratings. Section 98.34(c) and section 98.34(d)(3) require routine measurement of the higher heat value (HHV) and carbon content of fuels, respectively. BP requests that EPA allow the use of HHVs obtained from the fuel provider. BP further requests that EPA include an option to decrease the frequency of sampling to annually if several consecutive measurements show minimum variation in the HHV or carbon contents.

Response: EPA acknowledges the commenters' concerns, and has defined the term "company records" in §98.6 of the final rule. EPA believes that the revised definition provides appropriate guidance as to what records a facility may use to determine fuel consumption.

The final rule clarifies that fuel sampling and analysis data provided by the supplier may be used in the emission calculations, and that fuel billing meters may be used to quantify fuel consumption. To simplify the emission calculations in Tiers 2 and 3, averaging of HHV and carbon content data is permitted if these data are obtained at least at the minimum frequency specified in §98.34. If the results of fuel sampling are received monthly or more frequently, the weighted annual average high heat value shall be calculated using Equation C-2b. If the results of fuel sampling are received less frequently than monthly, then the annual average HHV shall be calculated using the arithmetic average HHV for all valid samples for the year. However, regardless of the sampling frequency, the owner or operator must use the results of all available valid fuel analyses in the emissions calculations.

Commenter Name: Karen St. John
Commenter Affiliation: BP America Inc. (BP)
Document Control Number: EPA-HQ-OAR-2008-0508-0631.1
Comment Excerpt Number: 67

Comment: Section 98.34(d)(1) Tier 3 Calculation Methodology require fuel flow meters be recalibrated annually or at the minimum frequency specified by the manufacturer. Recalibration and/or reverification should not be required on an arbitrary frequency (i.e. annually), but based on manufacturer recommendations or an alternate frequency determined to be appropriate through operating experience for the meter and good manufacturing practices. BP suggests the following alternative text for Section 98.34(d): (1) All oil and gas flow meters (except for gas billing meters) shall be calibrated or verified on a documented schedule consistent with good industry practice, using an applicable industry standard method or the calibration procedures specified by the flow meter manufacturer or developed and documented by the facility for the device. Fuel flow meters shall be recalibrated or reverified either annually or following good manufacturing practice. (2) Oil tank drop measurements (if applicable) shall be performed according to one of the methods developed by a consensus standards organization. (3) The carbon content of the fuels listed in paragraphs (c)(1) and (2) of this section shall be determined monthly. For other gaseous fuels (e.g., refinery gas, or process gas), monthly sampling and analysis is required to determine the carbon content and molecular weight of the fuel. If a specific gravity or density analyzer is used to measure the properties of the gas, a correlation with the carbon content must be demonstrated by periodic sampling. An applicable method listed in Sec. 98.7 shall be used to determine the carbon content and (if applicable) molecular weight of the fuel.

Response: Section 98.34 has been revised to require facilities to retain the daily sampling requirement for other gaseous fuels, but only for facilities with existing equipment in place that is capable of providing the data. Otherwise, weekly sampling is required, which may be postponed in favor of monthly sampling until 2011 if new equipment must be purchased or if existing equipment must be upgraded to meet the weekly sampling and analysis requirements. The more frequent sampling for process gas is due to its variability.

EPA believes that the language in §98.34 is clear, offers substantial flexibility, and does not require the revision suggested by the commenter.

EPA defines acceptable test methods as those listed in §98.7 or the calibration procedures specified by the flow meter manufacturer.

Commenter Name: See Table 6
Commenter Affiliation:
Document Control Number: EPA-HQ-OAR-2008-0508-0679.1
Comment Excerpt Number: 107

Comment: §98.34. Calibrated flow meters are not addressed for a Tier 1 or Tier 2 calculation approach. If using Tiers 1 or 2, rated horsepower/operating hours etc should be acceptable as legitimate "company records to quantify fuel consumption." Note, equation definitions for Tiers 1 and 2 indicates fuel flow, but do not use the term "company records." The inconsistency is vague and confusing. API is assuming that Tiers 1 and 2 do not require fuel meters, and that the use of company records includes estimation methods as outlined in the Compendium, based on operating hours and ratings.

Response: EPA acknowledges the commenters' concerns, and has defined the term "company records" in §98.6 of the final rule. EPA believes that the revised definition provides appropriate guidance as to what records a facility may use to determine fuel consumption.

Commenter Name: See Table 6
Commenter Affiliation:
Document Control Number: EPA-HQ-OAR-2008-0508-0679.1
Comment Excerpt Number: 108

Comment: §98.34(c) and §98.34(d)(3) require routine measurement of the higher heat value (HHV) and carbon content of fuels, respectively. The reporter should be allowed to use fuel specifications that include, but are not limited to, regulatory requirements, data provided by fuel suppliers, and specifications set by the reporter to determine HHV and carbon content. The frequency for determining HHV or carbon content from data obtained from a fuel supplier should be the same frequency for obtaining the data from the supplier. Also, similar to other CAA rules, the rule should include an option to decrease the frequency of sampling to annually if several consecutive measurements show minimum variation in the HHV or carbon contents.

Response: The final rule clarifies that fuel sampling and analysis data provided by the supplier may be used in the emission calculations, and that fuel billing meters may be used to quantify fuel consumption. To simplify the emission calculations in Tiers 2 and 3, averaging of HHV and carbon content data is permitted if these data are obtained at least at the minimum frequency specified in §98.34. If the results of fuel sampling are received monthly or more frequently, the weighted annual average high heat value shall be calculated using Equation C-2b. If the results of fuel sampling are received less frequently than monthly, then the annual average HHV shall be calculated using the arithmetic average HHV for all valid samples for the year. However, regardless of the sampling frequency, the owner or operator must use the results of all available valid fuel analyses in the emissions calculations.

Commenter Name: See Table 6
Commenter Affiliation:
Document Control Number: EPA-HQ-OAR-2008-0508-0679.1
Comment Excerpt Number: 109

Comment: §98.34. Where monthly fuel analyses are required, characterizations performed by the fuel supplier should be acceptable. It is noted in the Preamble (p. 16484) that "EPA considered allowing affected facilities to rely exclusively on the results of fuel sampling and analysis provided by fuel suppliers, rather than performing periodic on-site sampling for all variables [but EPA] decided not to propose this because in most instances, only the fuel heating value, not the carbon content, is routinely provided by fuel suppliers." If a fuel supplier provides carbon content, this data should be permitted in Tier 3 calculations. Note that the implication of this finding is not limited to subpart C, but has implications for other subparts (P, Y, etc.) Allowing a facility to substitute carbon contents specified by the fuel supplier will assist in reducing the overall reporting burden. API suggests one annual value from the supplier should be acceptable as the carbon content of these fuels is very stable.

Response: The final rule clarifies that fuel sampling and analysis data provided by the supplier may be used in the emission calculations, and that fuel billing meters may be used to quantify fuel consumption. To simplify the emission calculations in Tiers 2 and 3, averaging of HHV and carbon content data is permitted if these data are obtained at least at the minimum frequency specified in §98.34. If the results of fuel sampling are received monthly or more frequently, the weighted annual average high heat value shall be calculated using Equation C-2b. If the results of fuel sampling are received less frequently than monthly, then the annual average HHV shall be calculated using the arithmetic average HHV for all valid samples for the year. However, regardless of the sampling frequency, the owner or operator must use the results of all available valid fuel analyses in the emissions calculations.

Commenter Name: See Table 6
Commenter Affiliation:
Document Control Number: EPA-HQ-OAR-2008-0508-0679.1
Comment Excerpt Number: 110

Comment: §98.34(d)(1). The statement "All oil and gas flow meters" should be revised to "All liquid and gas flow meters".

Response: EPA has revised the language in §98.34 of the final rule to read as follows: "Each oil and gas flow meter that provides fuel usage data for the GHG emissions reported under this part…" While this does not explicitly specify liquid flow meters, the Agency believes the provisions for liquid flow meters are implied.

Commenter Name: See Table 6
Commenter Affiliation:
Document Control Number: EPA-HQ-OAR-2008-0508-0679.1
Comment Excerpt Number: 111

Comment: §98.34(d)(3). Where the Tier 3 Calculation Methodology is used, reporters are required to determine the carbon content of natural gas, biogas, liquid fuels, and solids fuels monthly and of other gaseous fuels such as refinery gas and process gas on a daily basis. For many refinery and natural gas operations, the carbon content of gas streams does not vary significantly enough to warrant daily determination. EPA acknowledges in the definition of natural gas provided in §98.6 that the composition of fuel gas and process gas are similar to natural gas. Thus, EPA should revise the requirement in §98.34(d)(3) to specify that the reporter must determine the content of gaseous fuels monthly. Daily sampling is excessive for fuels that are fairly stable in composition. API recommends the use of the natural gas factor in Table C-1 or where the gas stream does fluctuate with operational changes, to determine a sampling frequency that is consistent with the variability of the stream. In addition, engineering analysis should be allowed to estimate carbon content instead of sampling for streams where there are safety concerns such as process gases that are maintained at high temperature to avoid liquid accumulation. The oil and gas flow meters used for this category have been installed and are operated following a wide variety of procedures. The reporter should maintain them in an appropriate manner, but specifying the exact appropriate methods would be very difficult for EPA. API recommends that reporters be allowed to determine the best methods and necessary frequencies for calibration and/or verifying flow measurement devices. API offers the following revised language for §98.34(d) [Page 16636]: Sec. 98.34 Monitoring and QA/QC requirements. (d) For the Tier 3 Calculation Methodology: (1) All oil and gas flow meters (except for gas billing meters) shall be calibrated or verified on a documented schedule consistent with good industry practice, using an applicable industry standard method or the calibration procedures specified by the flow meter manufacturer or developed and documented by the facility for the device. Fuel flow meters shall be recalibrated/reverified either annually or following good industry practice. (2) Oil tank drop measurements (if applicable) shall be performed according to one of the methods developed by a consensus standards organization. (3) The carbon content of the fuels listed in paragraphs (c)(1) and (2) of this section shall be determined monthly. For other gaseous fuels (e.g., refinery gas, or process gas), monthly sampling and analysis is required to determine the carbon content and molecular weight of the fuel. If a specific gravity or density analyzer is used to measure the properties of the gas, a correlation with the carbon content must be demonstrated by periodic sampling. An applicable method listed in Sec. 98.7 shall be used to determine the carbon content and (if applicable) molecular weight of the fuel.

Response: Section 98.34 has been revised to require facilities to retain the daily sampling requirement, but only for facilities with existing equipment in place that is capable of providing the data. Otherwise, weekly sampling is required, which may be postponed in favor of monthly sampling until 2011 if new equipment must be purchased or if existing equipment must be upgraded to meet the weekly sampling and analysis requirements.

EPA believes that the methods, derived from §98.7 and listed in §98.34(d) of the final rule, provide operators adequate flexibility for best practices concerning calibration and/or verifying flow measurement devices. Operators may also use the calibration procedures specified by the flow meter manufacturer. In the case of oil tank drop measurements, those shall be performed according to methods listed in §98.34.

The Agency is not opposed to alternative approaches for estimating carbon contents of fuels, such as with appropriate engineering analysis as described by the commenter. However, the commenter did not provide any supplementary information, proposed rule language, or cost analysis to explain how this proposed methodology could be implemented. In view of this, EPA has not incorporated the commenter's suggested approach into the final rule, but is willing to consider it in a future rulemaking, if the necessary technical details of the method are provided for Agency review.

Commenter Name: See Table 5
Commenter Affiliation:
Document Control Number: EPA-HQ-OAR-2008-0508-0480.1
Comment Excerpt Number: 38

Comment: INGAA recommends including additional fuel rate measurement methods and adding a streamlined approach for accepting additional methods. Proposed Section §98.7 includes a long list of accepted consensus method for measurement of fuel rate, gas quality (carbon content), fuel heating value, etc. INGAA has identified additional methods that should be included. In addition, as evident by the long list of methods already identified, there are many accepted methods for measuring fuel rate, heating value, etc. and method refinements and advances continue. Because of the breadth of coverage of the Proposed Rule, there needs to be a streamlined approach for accepting additional methods to address Subpart C measurement requirements for fuel flow, fuel carbon analysis, and heating value. Many of the ASTM standards referenced in §98.7 are not generally recognized as measurement standards for natural gas sector operations. To date, INGAA has identified the following additional methods that should be added to §98.7: AGA Report No. 3: Orifice Metering of Natural Gas Part 1: General Equations & Uncertainty Guidelines (1990). AGA Report No. 3: Orifice Metering of Natural Gas Part 3: Natural Gas Applications (1992). AGA Report No. 3: Orifice Metering of Natural Gas Part 4: Background, Development Implementation Procedure (1992). AGA Report No. 5: Natural Gas Energy Measurement. AGA Report No. 7: Measurement of Natural Gas by Turbine Meter (2006). AGA Report No. 8: Compressibility Factor of Natural Gas and Related

Hydrocarbon Gases (1994) AGA Report No. 9: Measurement of Gas by Multipath Ultrasonic Meters (2007) AGA Report No. 10: Speed of Sound in Natural Gas and Other Related Hydrocarbon Gases AGA Report No. 11: Measurement of Natural Gas by Coriolis Meter (2003) ANSI B 109.3: Rotary-Type Gas Displacement Meters (2000) GPA 21 45-09: Table of Physical Properties for Hydrocarbons and Other Compounds of Interest to the Natural Gas Industry. GPA 21 72-09: Calculation of Gross Heating Value, Relative Density, Compressibility and Theoretical Hydrocarbon Liquid Content for Natural Gas Mixtures for Custody Transfer GPA 2261-00: Analysis of Natural Gas and Similar Gaseous Mixtures by Gas Chromatography API 21.1: Manual of Petroleum Measurement Standards Chapter 21 - Flow Measurement Using Electronic Metering Systems Section 1 - Electronic Gas Measurement.

Response: EPA acknowledges the commenter's concerns, and has significantly revised §98.34 concerning fuel sampling and analysis. In addition, EPA has revised §98.34(c)(2)(i) to require semiannual sampling and analysis for natural gas. The Agency believes these changes should alleviate some of the commenter's concerns.

Commenter Name: Sean M, O'Keefe
Commenter Affiliation: Hawaiian Commercial and Sugar Company (HC&S)
Document Control Number: EPA-HQ-OAR-2008-0508-1138.1
Comment Excerpt Number: 11

Comment: EPA requests comment on ways to ensure that the feed rate of solid fuel to a combustion device is accurately measured. Typically, sugar mill boilers do not employ weighing equipment or other metering devices to directly determine the feed rate of sugarcane bagasse into the boiler; instead, a variety of methods may be used to estimate the quantity of bagasse combusted in a particular unit each year. These methods may not lend themselves to producing scientifically-based estimates of accuracy. In Hawaii, the total tonnage of bagasse produced by a sugar mill is determined on an ongoing basis and annually based upon the amount of cane processed; generally, all of the bagasse is assumed to have been burned for fuel by the end of the grinding season with the exception of a small percentage that is used for filter cake. For facilities with multiple boilers, facility-wide bagasse consumption is apportioned to individual boilers based upon boiler operating data (e.g., steam production or bagasse feeder operation). Such methods have been accepted as sufficiently accurate for determining and reporting annual emissions of criteria pollutants, and should therefore also be acceptable for the purposes of estimating annual GHG emissions. Moreover, because GHG emissions are estimated based upon fuel-specific factors rather than on boiler-specific factors (unlike criteria pollutant emission factors which may vary considerably depending upon the particular unit in which a fuel is burned), obtaining an accurate estimate of the total amount of fuel burned at a facility is sufficient to determine the facility's GHG emissions; it is not necessary to know precisely how much of that fuel was burned in individual units. EPA should recognize that for many industries available means of measuring solid fuel consumption, particularly for biomass fuels combusted as part of an integrated production process, while limited, are adequate to provide reasonably accurate estimates of annual GHG emissions. EPA should not unnecessarily restrict a facility's ability to continue to utilize existing methods of monitoring fuel consumption.

Response: EPA acknowledges the commenter's concerns, and has significantly revised §98.34 concerning fuel sampling and analysis. In particular, the revised rule allows "company records" as defined in §98.6 to be used to quantify fuel consumption. In addition, EPA has extended the use of steam production and combustion unit efficiency to calculate CO_2 emissions to other solid fuels in addition to municipal solid waste. These parameters may also be used to quantify the amount of biomass combusted in a unit.

Commenter Name: See Table 6
Commenter Affiliation:
Document Control Number: EPA-HQ-OAR-2008-0508-0679.1
Comment Excerpt Number: 112

Comment: §98.34(d)(1) and (3) (Page 16636): The continuous monitoring of flow rate and daily sampling for carbon content proposed in §98.34(d)(1) and (3) for process gases assumes the vents are continuous. Some process gas vents, however, are intermittent or are only generated during emergency situation. Quantification of such process gases should be handled under a de minimis threshold or calculated using engineering analysis.

Response: Although the Agency does not agree that there should be a de minimis emissions exclusion, EPA has expanded the list of exempted source categories in §98.30 to include flares. The commenter should also consider §98.34 for revised methods to determine the carbon content of gaseous fuel.

Commenter Name: Lorraine Krupa Gershman
Commenter Affiliation: American Chemistry Council (ACC)
Document Control Number: EPA-HQ-OAR-2008-0508-0423.2
Comment Excerpt Number: 64

Comment: In §98.34(d)(3), facilities using process gas should be provided with an option to perform a statistical analysis to determine a sample and analytical frequency that is less often than daily, based on the potential for variations in process gas composition. Requiring daily sampling for all process fuels may be unnecessary. At a minimum, facilities should be allowed the option of initially sampling monthly and then using a different frequency if warranted by a statistical analysis.

Response: EPA acknowledges the commenter's concerns, and has significantly revised §98.34 concerning fuel sampling and analysis. Section 98.34 provides specific instructions concerning sampling and analysis of gaseous fuels. In addition, EPA has revised §98.34 of the rule, defining multiple methods for determining the carbon content for gaseous fuels. The Agency believes that these revisions should address the commenter's concerns.

Commenter Name: Lorraine Krupa Gershman
Commenter Affiliation: American Chemistry Council (ACC)
Document Control Number: EPA-HQ-OAR-2008-0508-0423.2
Comment Excerpt Number: 65

Comment: In §98.34(e)(1)(i), (ii), and (iii), the terms are redundant if it is presumed they are connected by "and" EPA should clarify this by connecting each of the terms (i), (ii), and (iii) by "or."

Response: EPA agrees that the proposed language could be confusing, and has added language to the final rule to clarify that any one of the alternate initial certification procedures for CO_2 CEMS is acceptable.

Commenter Name: Lorraine Krupa Gershman
Commenter Affiliation: American Chemistry Council (ACC)
Document Control Number: EPA-HQ-OAR-2008-0508-0423.2
Comment Excerpt Number: 66

Comment: No place in §98.34 does EPA provide a specified recommended methodology for measuring solid fuels. Requiring measurement of the fuel rate instead of allowing calculation would be especially burdensome and unnecessarily costly, and would require the installation of weighing equipment. Some sites currently calculate the amount of solid fuel combusted based on, for example in the case of a boiler, the amount of steam generated each month and the boiler efficiency. EPA should continue to allow such engineering calculations for solid fuel flow rate.
Response: EPA acknowledges the commenter's concerns, and has significantly revised §98.34 concerning fuel sampling and analysis. In particular, the revised rule allows "company records" as defined in §98.6 to be used to quantify fuel consumption. In addition, revised §98.34 refers to the calculations using steam produced as the basis for determining solid fuel combusted. The Agency believes that these revisions should address the commenter's concerns. Also, EPA has extended the use of steam production and combustion unit efficiency to calculate CO_2 emissions to other solid fuels in addition to municipal solid waste. These parameters may also be used to quantify the amount of biomass combusted in a unit.

Commenter Name: J. P. Blackford
Commenter Affiliation: American Public Power Association (APPA)
Document Control Number: EPA-HQ-OAR-2008-0508-0661.1
Comment Excerpt Number: 6

Comment: EPA, on page 16483 of the Preamble, is "allowing a January 1, 2011 compliance date to install CEMS to meet the Tier 4 requirements, if either a diluent gas monitor, flow monitor, or both, must be added. The January 1, 2011 deadline would allow sufficient time to purchase, install, and certify any additional monitor(s) needed to quantify CO_2 mass emissions." While APPA supports the extension of time to purchase, install, and certify the additional monitors, we are concerned that the extension is not sufficient for the following reasons: 1.

Some municipal utilities are on a July fiscal year with those budgets already virtually locked in for a period of 7/1/09 - 6/30/10. If they are forced to wait for the following budget year beginning 7/1/10, it will allow utilities only six months to purchase, install and certify the monitors. Some state legislatures' budgetary cycles do not allow additional expenditures without authorization during the first half of a calendar year. 2. The installation and calibration of CEMS may not be an easy task. APPA has utility members who have been required to make structural modifications to their stacks in order to get accurate flow measurements. In addition, some have cited concerns about the accuracy of the CEMS, potentially caused by air leakage and other operational parameters and the degradation of the EGU. 3. Consideration must also be given to the scheduled outages which are the most reasonable time for utilities to install the necessary CEMS. A later installation deadline is needed to enable this activity to occur during planned outages that are often scheduled years in advance. 4. Another issue for EPA to consider is whether industry has ample capacity to manufacture, install and certify these monitors within the originally suggested timeframe. In addition, as APPA utility members are part of their municipal government, they are required to follow standard procurement procedures when soliciting proposals for work. This will usually require multiple bids and may require more time to choose a contractor than would be required for a non-municipal utility. Given these issues, APPA requests that EPA extend the deadline to no earlier than July 1, 2011 for the installation of CEMS to meet the Tier 4 requirements. Units could use Tier 3 reporting methodologies until this time and this would allow EPA to collect GHG emissions data while allowing utilities ample time to install the required CEMS and have them certified as required in the proposed rule.

Response: EPA appreciates the commenter's concerns. Any CEMS that would be used to quantify CO_2 emissions would also have to be certified and undergo ongoing quality assurance testing according to the procedures specified in either: (1) 40 CFR Part 75; or (2) 40 CFR Part 60, Appendix B; or (3) a State monitoring program. Sources that have all of the necessary CEMS installed and certified by January 1, 2010 are required to use Tier 4 in 2010. However, for sources that need additional time to upgrade their CEMS, the monitor certification deadline is extended to January 1, 2011, and Tier 2 or Tier 3 methodology may be used in 2010.

See the response to comment EPA-HQ-OAR-2008-0508-1142.1, excerpt 26, for additional information on flexibility provided for the year 2010.

Commenter Name: William C. Herz
Commenter Affiliation: The Fertilizer Institute (TFI)
Document Control Number: EPA-HQ-OAR-2008-0508-0952.1
Comment Excerpt Number: 6

Comment: The language proposed in 40 C.F.R. §98.34(d)(3) states that "[f]or other gaseous fuels, daily sampling and analysis is required to determine the carbon content and molecular weight of the fuel." 74 Fed. Reg. at 16,636. For some combustion processes, such as an ammonia manufacturing facility, the composition of the fuel gas provided by the inert purge of the process does not vary in carbon content. In light of this, TFI proposes that quarterly sampling is sufficient for representative carbon content. Specifically for ammonia manufacturing units, the carbon content of the supplemental fuel is already accounted for, and should be excluded from the combustion calculation, as this would be double counting of the carbon. Weekly sampling would add approximately $20,000 per plant per year to comply with.

Response: EPA acknowledges the commenter's concerns, and has significantly revised §98.34 concerning fuel sampling and analysis. Section 98.34 provides specific instructions concerning sampling and analysis of gaseous fuels. In addition, EPA has revised §98.34 of the rule, defining multiple methods for determining the carbon content for gaseous fuels.

EPA intends that the stationary combustion source category include any device that meets the definition included in §98.30 for which emissions are not accounted for in the report through a separate subpart of the rule. Per the requirements in 40 CFR Part 98, Subpart A, facilities have to report GHG emissions from all source categories located at their facility, including stationary combustion and process emissions. EPA does not intend that emissions be double reported, and has revised the various subparts of the final rule to clarify the intent of the stationary combustion source category. EPA understands that if process and combustion emissions are not easily or logically separated, that combustion emissions may be reported in combination with process emissions, as may be the case with ammonia manufacturing.

Commenter Name: H. Allen Faulkner
Commenter Affiliation: Ascend Performance Materials, LLC, Decatur Plant
Document Control Number: EPA-HQ-OAR-2008-0508-1578
Comment Excerpt Number: 6

Comment: Ascend Decatur Alabama Plant uses Coriolis-based mass flow meters on some natural gas lines. The current requirements of 98.34(d)(I), state that gas flow meters must be recalibrated annually. There is no method for calibrating these meters on-line. Therefore, annual calibration would require the meter to be removed from service and shipped to a flow lab for calibration. This would require purchase of additional meters to ensure continuous operation during calibration down time. Ascend requests further guidance on the calibration of Coriolis-based mass flow meters. In addition, Ascend uses various other types of flow meters (i.e. orifice plates) which would be subject to annual recalibration requirement in 98.34(d)(1). Is it sufficient to check the transmitter calibration to meet this requirement or does the primary element and transmitter have to be tested together? If the primary element and transmitter have to be tested together, the procedure would require redundant meters be installed because the entire unit would have to be removed for testing.

Response: EPA acknowledges the concerns of the commenters. Section 98.34 of the final rule clarifies that for units and processes that use an orifice, nozzle, or venturi meter and operate continuously with infrequent outages, the owner or operator may postpone the initial calibration or PEI (as applicable) until the next scheduled maintenance outage. Therefore, an online calibration method will not be needed. For ongoing quality assurance, each flow meter shall be recalibrated either biannually (i.e., once every two years) or at the minimum frequency specified by the manufacturer. For the continuously-operating units and processes described in §98.34, the required flow meter and PEI recalibrations may be postponed until the next scheduled maintenance outage.

Commenter Name: Rhea Hale
Commenter Affiliation: American Forest & Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2008-0508-0909.1
Comment Excerpt Number: 8

Comment: AF&PA agrees with EPA's approach in 98.34(a) to allow sources latitude in determining fuel input and to maintain records of its methodologies. Facilities should be allowed to back-calculate fuel combustion quantities based on boiler steam generation quantities and boiler steam generation efficiencies, as discussed in EPA's Technical Support Document (TSD) for the Pulp and Paper Sector. As presented in Section 6.1 of the TSD, these back-calculated biomass fuel consumption quantities should then be used in conjunction with default emission factors for biomass fuels to calculate biogenic CO_2 emissions. This option should be explicitly allowed for combustion units burning only biomass, and for combustion units that burn a combination of biomass and fossil fuels. This option (determining fuel consumption quantities from steam production data and boiler efficiency) should also be allowed for determining biogenic CO_2 from combustion of spent pulping liquors in recovery furnaces.
Response: In response to comments, EPA has added a provision in §98.33(e)(6) specifically allowing facilities to back-calculate the quantity of solid fuel combusted using steam generation and boiler efficiency. EPA has provided an example calculation method, and has allowed facilities to use other similar methods, provided that they are documented and kept in the company's records as required by §98.3(g)(4).

Commenter Name: See Table 8
Commenter Affiliation:
Document Control Number: EPA-HQ-OAR-2008-0508-0709.1
Comment Excerpt Number: 8

Comment: We appreciate the provision in section 98.34(d)(1) which states that "All oil and gas flow meters (except for gas billing meters) shall be calibrated prior to the first year for which GHG emissions are reported under this part..." We strongly urge EPA insert a similar parenthetical to exclude gas billing meters from annual calibration, as follows: "Fuel flow meters (except for gas billing meters) shall be recalibrated either annually or at the minimum frequency specified by the manufacturer."

Response: EPA acknowledges the concerns of the commenters. Section 98.34 of the final rule has been clarified to exempt fuel billing meters from the calibration requirement, "provided that the supplier and the unit(s) combusting the fuel do not have any common owners and are not owned by subsidiaries or affiliates of the same company."

Commenter Name: Marc J. Meteyer
Commenter Affiliation: Compressed Gas Association (CGA)
Document Control Number: EPA-HQ-OAR-2008-0508-0981.1
Comment Excerpt Number: 24

Comment: The proposed rule defines the alternate initial certifications for CO_2 CEMS systems under §98.34(e)(1)(i), (ii), and (iii). The propose rule language is not clear that any one of the certifications described in §98.34(e)(1)(i), (ii), and (iii) is acceptable. CGA Comment: Clarify that any one of the alternate initial certifications under §98.34(e)(1)(i), (ii), and (iii) is acceptable by separating the (i), (ii), and (iii) options with "or".

Response: EPA agrees that the proposed language could be confusing, and has added language to the final rule to clarify that any one of the alternate initial certification procedures for CO_2 CEMS is acceptable.

Commenter Name: Renae Schmidt
Commenter Affiliation: CITGO Petroleum Corporation
Document Control Number: EPA-HQ-OAR-2008-0508-0726.1
Comment Excerpt Number: 11

Comment: CITGO recommends that EPA clarifies key QA/QC requirements in the Preamble to help owners and operators better understand calibration expectations. For example, orifice flow meters are commonly used for measuring refinery fuel gas to heaters and boilers. Orifice meters are typically "calibrated" by checking differential pressure (DP) cell. Direct calibration of the primary element (orifice plate) is not feasible and can not be field verified unless the fuel line is taken out of service which can be up to 8 years for some process heaters.

Response: EPA acknowledges the concerns of the commenters regarding the unique nature of orifice flow meters, and has clarified the final rule in §98.34. The initial quality assurance of an orifice meter requires only an in-situ calibration of the transmitters. For ongoing QA, the in-situ transmitter calibration shall be repeated at least annually, and the primary element inspection (PEI) shall be performed at least once every three years.

Commenter Name: Lorraine Krupa Gershman
Commenter Affiliation: American Chemistry Council (ACC)
Document Control Number: EPA-HQ-OAR-2008-0508-0423.2
Comment Excerpt Number: 62

Comment: In §98.34(d)(1), some flow meters may not be calibrated without shutting down the process. For example, in some cases, an orifice plate must be pulled out of the line to do a complete calibration. This might be part of manufacturer's recommendations as a part of calibration recommendations. It would not be practical to perform this yearly because equipment may not be out of service on a frequency of more than one time in every several years. The annual calibration should be limited to no more than would be required by Part 75 (electronic transmitter calibration) less the visual inspection every three years. In addition, for the reasons cited above regarding possible unit shutdown for a full calibration per manufacturer's recommendations, it may not be practical or possible to complete all required calibrations between now and January 1, 2010. ACC recommends that EPA allow owners/operators to continue utilizing existing flow meters until the next scheduled shutdown for calibration, if it requires a process unit shutdown.

Response: See the Preamble and separate comment response document volume for the response on Monitoring and QA/QC Requirements.

See the response to comment EPA-HQ-OAR-2008-0508-1142.1, excerpt 26, for more information on additional flexibility for 2010.

EPA acknowledges the concerns of the commenters regarding the unique nature of orifice flow meters, and has clarified the final rule in §98.34. The initial quality assurance of an orifice meter requires only an in-situ calibration of the transmitters. For ongoing QA, the in-situ transmitter calibration shall be repeated at least annually, and the primary element inspection (PEI) shall be performed at least once every three years. For the continuously-operating units and processes described in §98.34, the required flow meter and PEI recalibrations may be postponed until the next scheduled maintenance outage.

Commenter Name: Craig S. Campbell
Commenter Affiliation: Lafarge North America
Document Control Number: EPA-HQ-OAR-2008-0508-0674.1
Comment Excerpt Number: 12

Comment: When Subpart C Tier 3 is used, proposed 40 CFR §98.34(d)(3) requires: "The carbon content of the fuels listed in paragraphs (c)(1) and (2) of this section shall be determined monthly." Paragraph (c)(1) refers to monthly sampling of natural gas, biogas, and liquid fuels, and paragraph (c)(2) refers to weekly samples which are composited and analyzed monthly for coal and other solid fuels. Lafarge recommends that EPA amend the fuel sampling frequency requirements by adding a provision allowing gradual reduction in sampling frequency over time if the facility is able to make a showing that carbon content values remain within a statistically-appropriate range of variability. In addition, Lafarge wishes to point out that EPA's proposed weekly sampling with compositing for monthly analysis is not appropriate for all solid fuels used at cement plants. One example is solid tires ("tire-derived fuel"), which as a practical matter cannot be sampled for carbon content testing on a weekly basis. Construction of a typical passenger vehicle tire includes numerous components. A constructed tire has these various components placed at specific locations per the design requirements of the tire, and is therefore entirely non-homogeneous. Components include various synthetic rubbers, natural rubber, carbon black, nylon ply's, steel belts and beads, and other components. In light of its non-homogeneity, representative sampling of a tire is a complex labor-intensive exercise that cannot reasonably be done on a weekly basis. The more practical method is to characterize tire carbon content by using a "database average value" based upon representative sampling efforts conducted over a much longer time span. A reasonable database average approach would be annual sampling and use of a 5-year average. Lafarge also wishes to emphasize that the tire-derived-fuel is just one example which supports use of a "database average approach" as opposed to weekly/monthly sampling and analysis. EPA should provide flexibility in the rule language to address the wide variety of possible alternative fuels warranting use of the database average approach. A somewhat different need for flexibility arises with some types of alternative fuels derived from other distinct manufactured products. For example, some cement plants use a particular alternative fuel derived from one particular product such as discarded CD cases, off-spec diapers, or another distinct product. As a rule, the composition and carbon content remains constant for any alternative fuel derived from any one distinct manufactured product. In this situation an initial characterization, and less frequent (e.g., annual) confirmation testing would be appropriate. Weekly/monthly sampling and analysis of these types of alternatives fuels would be excessive and should not be required under the regulation. Overall, we believe it is important that EPA provide more flexibility in terms of sampling method and frequency for all types of solid fuels other than coal and petroleum coke. Lafarge recommends that EPA at least add specific provisions to allow: A.) use of long-term database averages for mixed alternative fuels and non-heterogeneous alternative fuels (e.g., tire-derived fuel), and B.) initial characterization with less-frequent confirmation sampling for a solid fuel derived from a distinct manufactured product (e.g., CD cases, diapers, etc.).

Response: EPA acknowledges and appreciates the commenter's concerns. Section 98.34 has been revised to require that natural gas be sampled semiannually and to require a representative sampling for each fuel lot (i.e., for each shipment or delivery) for fuel oil and coal. For other liquid fuels and biogas, quarterly sampling is required. For other solid fuels, excluding municipal solid waste, weekly composite sampling with monthly analysis is required. For other gaseous fuels, the daily sampling requirement has been retained, but only for facilities with existing equipment in place that is capable of providing the data. Otherwise, weekly sampling is required, which may be postponed in favor of monthly sampling until 2011 if new equipment must be purchased or if existing equipment must be upgraded to meet the weekly sampling and analysis requirements.

The final rule clarifies that fuel sampling and analysis data provided by the supplier may be used in the emission calculations, and that fuel billing meters may be used to quantify fuel consumption. To simplify the emission calculations in Tiers 2 and 3, averaging of HHV and carbon content data is permitted if these data are obtained at least at the minimum frequency specified in §98.34. If the results of fuel sampling are received monthly or more frequently, the weighted annual average high heat value shall be calculated using Equation C-2b. If the results of fuel sampling are received less frequently than monthly, then the annual average HHV shall be calculated using the arithmetic average HHV for all valid samples for the year. However, regardless of the sampling frequency, the owner or operator must use the results of all available valid fuel analyses in the emissions calculations.

EPA has revised the use of Tier 3 in §98.33(b)(3) of Subpart C to be required only when a unit with a maximum rated heat input capacity greater than 250 mmBtu/hr that combusts any type of fuel listed in Table C-1 of this subpart (except MSW), unless the use of Tier 1 or 2 is permitted or Tier 4 is required. Tier 3 is also required for a unit with a maximum rated heat input capacity greater than 250 mmBtu/hr that combusts a fuel that is not listed in Table C-1 of this subpart provided that the use of Tier 4 is not required and the fuels provide ten percent or more of the annual heat input to the unit or to a group of units served by common supply pipe, as described in §98.36(c)(3).

It is also noted that Tier 1 may be used for any fuel listed in Table C-1 that is combusted in a unit with a maximum rated heat input capacity of 250 mmBtu/hr or less.

The Agency is not opposed to alternative approaches for fuel sampling, such as specific allowances for annual sampling and use of a 5-year average as described by the commenter. However, the commenter did not provide any supplementary information, proposed rule language, or cost analysis to explain how this proposed methodology could be implemented. In view of this, EPA has not incorporated the commenter's suggested approach into the final rule, but is willing to consider it in a future rulemaking, if the necessary technical details of the method are provided for Agency review.

Commenter Name: Renae Schmidt
Commenter Affiliation: CITGO Petroleum Corporation
Document Control Number: EPA-HQ-OAR-2008-0508-0726.1
Comment Excerpt Number: 12

Comment: Performance specifications are already in place for the continuous monitoring of CO_2, flow measurement devices and other monitoring and measuring devices specified in the Inventory Rule. Calibration, Testing, Certification and QA/QC for these devices are well established and time tested. Requiring additional procedures around these monitors is expensive and burdensome, not to mention leading to additional downtime on monitors that serve for both the GHG Reporting Rule and other rules. EPA should refer to and rely upon the existing standards for monitoring equipment and adopt them by reference in the Rule.

Response: EPA believes that the methods listed in §98.34 of the final rule, derived from §98.7, provide operators adequate flexibility for best practices. Operators may also use the calibration procedures specified by the flow meter manufacturer. In the case of oil tank drop measurements, those shall be performed according to any consensus based standard.

Commenter Name: Kathy G. Beckett
Commenter Affiliation: West Virginia Chamber of Commerce
Document Control Number: EPA-HQ-OAR-2008-0508-0956.1
Comment Excerpt Number: 16

Comment: Proposed §98.34(c)(2), specifies weekly sampling to develop a composite for monthly analysis of for coal, and other solid fuels. EPA should clarify its description and equation to reflect the more specific provisions in §98.34(c). Carbon content is measured monthly for natural gas, biogas, and liquid fuels, monthly for coal and other solid fuel (based on a weekly composite), and daily for other gaseous fuel (e.g., refinery gas or process gas). Proposed §98.34(d)(3). EPA assumes that daily measurements would be made with in-line gas chromatographs that are already in place for process purposes. 74 Fed. Reg. 16484. All oil and gas flow meters (except for gas billing meters) must be calibrated prior to the first reporting year using either a test method listed in §98.7 or "the calibration procedures specified by the flow meter manufacturer," and must be recalibrated either annually or "at the minimum frequency specified by the manufacturer." Proposed §98.34(d)(1). For both Tier 2 and Tier 3 methodologies, only those sampling and analysis methods incorporated under proposed §98.7 can be used. Proposed §98.34(c) and (d). To ensure that this list is complete and that the methods provided are up to date, the Chamber requests that EPA also allow use of any applicable method incorporated under 40 C.F.R. §75.6.

Response: EPA has incorporated by reference all methods deemed appropriate into Part 98, and therefore does not believe it is necessary to allow the use of methods listed under 40 C.F.R §75.6. The commenter should note that the EPA has substantially revised §98.34(c). According to the final rule, at least one representative sample from each lot of coal must be sampled. For other solid fuels (other than municipal solid waste), the final rule retains the original provision to sample weekly and analyze a monthly composite sample. EPA has also revised §98.33(a)(2), concerning the Tier 2 Methodology, to clarify the calculations required depending on the frequency of fuel sampling.

Commenter Name: Kathy G. Beckett
Commenter Affiliation: West Virginia Chamber of Commerce
Document Control Number: EPA-HQ-OAR-2008-0508-0956.1
Comment Excerpt Number: 17

Comment: Of concern is the need to ensure that units that do not already have required monitoring installed have sufficient time to order, install, and perform any necessary testing on that equipment prior to the start of the program. EPA has attempted to address that sort of concern in proposed §98.33(b)(6), which provides that if the monitors needed to report under Tier 4 have not been installed and certified by January 1, 2010, the unit may use Tier 3 in 2010. While the Chamber believes that the relief provided by this provision is necessary, it is incomplete. Reporting under Tier 3 also requires monitoring equipment for gaseous fuels -- fuel flow meters and, for some fuels, gas chromatographs -- that need to be installed and calibrated. In finalizing the rule, EPA must ensure that sufficient time and resources are available for installation and calibration of this equipment.

Response: See the response to comment EPA-HQ-OAR-2008-0508-1142.1, excerpt 26, for more information on flexibility for 2010. EPA agrees that there was not sufficient time given for installation and calibrations of fuel flow meters, and has revised §98.34(d) concerning installation and calibration, such that the deadline has been extended one year, to January 1, 2011. For flow monitors previously calibrated using the manufacturer's recommended methods, an additional calibration is not required by January 1, 2011 if the calibration is still active, but a calibration must be performed before the time interval recommended by the manufacturer elapses.

Commenter Name: See Table 3
Commenter Affiliation:
Document Control Number: EPA-HQ-OAR-2008-0508-0433.2
Comment Excerpt Number: 18

Comment: NPRA recommends that a source consuming common commercial fuels may, at the source's option: 1. Use the standard GHG emission factors provided in the rule; or 2. Use an annual average heat value or carbon content determination performed by the supplier of the common commercial fuel; or 3. Perform a single, annual sampling and analysis for heat value or carbon content; and 4. Exclude mandatory sampling and characterization of a fuel stream that accounts for less than 1% of the facility's GHG emissions. As part of the proposed rule, §98.33(b) defines which calculation Tier can be used for different size/fuel sources: §98.34(c)(1) requires natural gas to be sampled and tested for heat value monthly, §98.34(d)(3) requires natural gas to be sampled and tested for carbon content monthly but requires other gaseous fuels to be sampled and tested for carbon content and molecular weight daily, and §98.164(c) requires gaseous feedstocks to be sampled and tested for carbon content monthly. In some cases, a reasonable approach (method, frequency, responsibility, and alternate methods) to characterizing fuels and feedstocks is allowed; in other cases excessive approaches are required. In addition, comparably accurate methods for estimating emissions from common fuels (e.g., standard emission factors) are restricted to smaller combustion units, potentially increasing the burden on the regulated source with no resultant improvement in the quality of the emissions data. Many combustion-related sources utilize common fuels of commerce, which are well characterized and must meet specific industry standards for commercial sale. For such fuels, use of standard emissions factors is a suitable approach to determine an estimate of GHG emissions, as it is within the margin of error of all the other relevant measured/estimated values. A particularly clear example is utility-supplied natural gas, regarding which even the Preamble cites that the average carbon content is within 1% for all common gas supplies. Furthermore, under Subpart NN applicable to this source category responsible for emissions of 1,115 million metric tons or 16.4% of the national total, the Preamble states (74 FR 68, p 16577) that the proposed rule will not require the local gas distribution companies to sample and analyze natural gas periodically. The proposed rule itself (74 FR 68, pp 16721 - 16722) requires the use of one of two simple equations that rely on EPA default emission factors. If the agency is committed to monthly characterizations of these common fuels, the agency should accept analysis performed by the fuel supplier. While use of supplier-generated data is suggested in the Preamble, it is not clearly articulated as an allowed approach in the proposed rule itself. Allowing supplier generated characterization data to be used would significantly reduce the amount of redundant sampling and analysis, in many cases by sources that have no experience in such sampling or analysis, in favor of centralized fuel characterization by entities who are already conducting such sampling and analysis on a regular basis. To ensure the benefit of such an approach NPRA recommends the agency make the characterization of common commercial fuels by the suppliers a requirement under the mandatory reporting rule. Likewise, on the basis that the source is striving to calculate an annual emission estimate, NPRA believes daily characterization of fuel gases (e.g., refinery fuel gas) creates excessive costs and risks in sampling and analysis of such flammable gas streams. NPRA recommends the source conduct monthly sampling and analysis and apply the average of the 12 monthly samples to the annual fuel consumption to yield the annual emission estimate. NPRA understands that EPA seeks an accurate characterization of all fuel gases, and acknowledges that some sources of fuel gas (e.g., refinery fuel gas) can vary with time. However, NPRA recommends that agency at a minimum should adopt an approach that allows a source to establish the average characteristics (heat value or carbon content, as appropriate for the Tier calculation method employed) of the fuel gas through multiple measurements (minimum 4 per month) and, if the variation between measurements falls within a 5% control limit, weekly characterization can be reduced to monthly. If a monthly sample falls outside the 5% limit, the source must return to daily characterization until the 5% control limit can be restored. This approach allows the significant cost associated with sampling and analysis to be reduced when it can be demonstrated that the accuracy of the accounting method meets the program objectives. Tier 1 and 2 methods which allow the use of the default emission factors for calculating combustion emissions are restricted to combustion sources less than 250 MM BTU/hr. For many common fuels, natural gas in particular, the carbon content and heat content are very consistent, allowing standard emission factors to be reliable estimates. Combined with an appropriately accurate flow measurement of fuel consumption, these can be used to provide an accurate and cost effective determination of the resultant GHG emissions. The hydrogen production section (specifically, §98.164(c) requires gaseous feedstocks to be only sampled and tested for carbon content monthly, regardless of the type of feedstock (e.g., natural gas or refinery fuel gas), while the stationary combustion section requires all gaseous fuel sources, other than natural gas, to be characterized on a daily basis. For the reasons noted above, and to be consistent with the approach provided in §98.164(c), NPRA recommends EPA require all gaseous fuels to be characterized no more frequently than monthly (modify §98.34(d)(3)) and in all cases, allow the characterization to be provided by the supplier of the fuel/feedstock (modify §98.34(c), §98/34(d)(3), and §98.164(c)), consistent with the intent described in the Preamble.

Response: EPA acknowledges and appreciates the commenter's concerns. EPA has revised the rule to allow large (greater than 250 mmBtu/hr) units that burn only natural gas or distillate oil to use Tier 2. EPA has also revised sampling frequencies, and now requires that natural gas be sampled semiannually and to require a representative sampling for each fuel lot (i.e., for each shipment or delivery) for fuel oil and coal. For other liquid fuels and biogas, quarterly sampling is required. For other solid fuels, excluding municipal solid waste, weekly composite sampling with monthly analysis is required. For other gaseous fuels, the daily sampling requirement has been retained, but only for facilities with existing equipment in place that is capable of providing the data. Otherwise, weekly sampling is required, which may be postponed in favor of monthly sampling until 2011 if new equipment must be purchased or if existing equipment must be upgraded to meet the weekly sampling and analysis requirements.

The final rule clarifies that fuel sampling and analysis data provided by the supplier may be used in the emission calculations, and that fuel billing meters may be used to quantify fuel consumption. To simplify the emission calculations in Tiers 2 and 3, averaging of HHV and carbon content data is permitted if these data are obtained at least at the minimum frequency specified in §98.34. If the results of fuel sampling are received monthly or more frequently, the weighted annual average high heat value shall be calculated using Equation C-2b. If the results of fuel sampling are received less frequently than monthly, then the annual average HHV shall be calculated using the arithmetic average HHV for all valid samples for the year. However, regardless of the sampling frequency, the owner or operator must use the results of all available valid fuel analyses in the emissions calculations.

Commenter Name: Michael Carlson
Commenter Affiliation: MEC Environmental Consulting
Document Control Number: EPA-HQ-OAR-2008-0508-0615
Comment Excerpt Number: 19

Comment: The proposed requirement of a description of the quality assurance procedures used (e.g., calibration of instrumentation) as part of the Tier 1 or Tier 2 emissions calculation methodology (16486) is inappropriate for many facilities which rely on metering devices owned, operated, and controlled by the fuel supplier or utility, which is completely separate and independent entity. This requirement would unnecessarily burden industrial and commercial facilities which would need to contact the fuel suppliers and utilities for this information. The requirement would also create an undue burden on fuel suppliers and utilities which would have to respond to facility requests for information on meter specifications and calibration data.
Response: EPA acknowledges the concerns of the commenters. Section 98.34 of the final rule has been clarified to exempt fuel billing meters from the calibration requirement, "provided that the supplier and the unit(s) combusting the fuel do not have any common owners and are not owned by subsidiaries or affiliates of the same company."

Commenter Name: Ronald H. Strube
Commenter Affiliation: Veolia ES Solid Waste
Document Control Number: EPA-HQ-OAR-2008-0508-0690.1
Comment Excerpt Number: 20

Comment: The NSPS JJJJ requires performance testing on stationary electrical generation engines every 8760 hours or 3 years of operation. This testing should be sufficient for electrical generation equipment.

Response: EPA does not understand the comment, and is unclear on how the performance testing relates to calculation and reporting of GHG emissions. See the Preamble, Section III., for a general description of the approach and response to comments for Subpart D Electricity Generation.

Commenter Name: Marc J. Meteyer
Commenter Affiliation: Compressed Gas Association (CGA)
Document Control Number: EPA-HQ-OAR-2008-0508-0981.1
Comment Excerpt Number: 22

Comment: The proposed rule requires periodic sampling and analysis of fuels for HHV or carbon content under §98.34(c)(1) and (2) and §98.34(d)(3). The rule implies this sampling and analysis is to be done by the consumer of the fuel, the reporting source. The proposed rule further describes minimum sampling and analysis frequencies for each fuel type. The proposed rule implies a need for characterization of standard commercial fuels to meet calculation method Tier 2 and 3, when, in actuality, the HHV and carbon content of standard fuels are nearly constant values and default values (e.g. Tier 1 calculation method) yield sufficiently accurate emission estimates. Recognizing the objective of the reporting rule is to develop a reasonable estimate of the annual emissions from a source: Standard fuels of commerce (natural gas, LP gas, fuel oils, etc.) that are supplied to multiple consumers are more efficiently characterized by their suppliers than by their consumers. Standard fuels of commerce (excepting coal) have very consistent HHV and carbon contents, requiring much lower characterization frequency. Monthly characterization, as required under §98.34(c)(1) and §98.34(d)(3), of such consistent fuels is costly and does not materially improve the annual estimate of emissions. Process-specific fuel sources (e.g. refinery gas) vary over time, but requiring daily sampling and analysis is very burdensome and costly for a degree of characterization that is intended to yield an annual emission estimate. CGA Comment: The characterization of standard fuels of commerce should not be required since default values employed under the Tier 1 calculation method will yield a sufficiently accurate emission estimate (per comments regarding §98.33(b)(1), (3), and (4), above). If a fuel characterization is required, the characterization sampling and analysis should be the responsibility of the fuel supplier. Such suppliers should then be required to provide the characterizations to any fuel consumers, upon request. The agency should then accept these characterizations for use under Tier 2 and 3 calculation methods. The characterization frequency of standard fuels of commerce should be reduced to annually. The characterization of process-specific fuels should be reduced to monthly. Alternately, a source should be able to demonstrate that, after a period of required characterization, the variability of the average fuel characteristic (HHV or carbon content) is sufficiently small to justify a reduction in the sampling and analysis burden.

Response: EPA acknowledges and appreciates the commenter's concerns. In the final rule, §98.34 has been revised to require that natural gas be sampled semiannually and to require a representative sampling for each fuel lot (i.e., for each shipment or delivery) for fuel oil and coal. For other liquid fuels and biogas, quarterly sampling is required. For other solid fuels, excluding municipal solid waste, weekly composite sampling with monthly analysis is required. For other gaseous fuels, the daily sampling requirement has been retained, but only for facilities with existing equipment in place that is capable of providing the data. Otherwise, weekly sampling is required, which may be postponed in favor of monthly sampling until 2011 if new equipment must be purchased or if existing equipment must be upgraded to meet the weekly sampling and analysis requirements.

In addition, the final rule clarifies that fuel sampling and analysis data provided by the supplier may be used in the emission calculations, and that fuel billing meters may be used to quantify fuel consumption. To simplify the emission calculations in Tiers 2 and 3, averaging of HHV and carbon content data is permitted if these data are obtained at least at the minimum frequency specified in §98.34. If the results of fuel sampling are received monthly or more frequently, the weighted annual average high heat value shall be calculated using Equation C-2b. If the results of fuel sampling are received less frequently than monthly, then the annual average HHV shall be calculated using the arithmetic average HHV for all valid samples for the year. However, regardless of the sampling frequency, the owner or operator must use the results of all available valid fuel analyses in the emissions calculations.

EPA has not required fuel suppliers to provide HHV and carbon content data to facilities, as it is the source's responsibility to determine emissions. Fuel suppliers have their own reporting requirements in other subparts. Addtionally, private sector contracts typically specify the terms of fuel related information provided by suppliers to purchasers.

Subpart KK, Suppliers of Coal, has not been included in this final rule. Subpart MM, Suppliers of Petroleum Products, and Subpart NN, Suppliers of Natural Gas, provide upstream reporters with the option of using default HHV and carbon contents or site specific sampling. EPA has not required fuel suppliers to provide HHV data to facilities, as provision of this type of information is typically addressed in private sector purchase contracts.

Commenter Name: Marc J. Meteyer
Commenter Affiliation: Compressed Gas Association (CGA)
Document Control Number: EPA-HQ-OAR-2008-0508-0981.1
Comment Excerpt Number: 23

Comment: The proposed rule requires all liquid and gaseous fuel flow meters to be calibrated initially and annually, or at the meter manufacturer's specified frequency, thereafter. This requirement fails to recognize that some fuel measurement device installations do not allow calibration without taking the fuel line out of service, thereby forcing a shutdown of the combustion/manufacturing process. In many instances, scheduled maintenance shutdowns for such equipment/processes will not occur on this prescribed frequency. Unless provisions are added to the proposed rule which provide relief from this required calibration frequency, manufacturing processes will be required to shutdown solely to complete the required calibration, resulting in significant cost, business disruption and, in many cases, increase environmental impacts from the inefficiencies of the start-up/shutdown activity. This need is comparable to provisions under many EPA rules regarding the repair of leaking VOC fugitive emissions components where repair would require a process shutdown, and instead the repair deadline is extended to the next scheduled maintenance shutdown. In most instances, the delay in calibration of a flow meter requiring a process shutdown would not materially compromise the annual emission estimate. This is particularly true for those combustion units using the simplest, cleanest fuels – there is typically less "drift" in the calibration of flow measurement devices for such clean fuels and such combustion units/processes often require less frequent maintenance turnarounds, exacerbating the need for extension of the calibration frequency. CGA Comment: The rule should include provisions for an extension of the required flow meter calibration deadline (as well as the initial calibration, if appropriate) where the calibration would require removing the fuel supply from service. The calibration requirement should then be extended to the next scheduled maintenance shutdown for the impacted unit/process.

Response: See the response to comment EPA-HQ-OAR-2008-0508-1142.1 excerpt 26, for more information on flexibility provided for 2010 reporting.

EPA acknowledges the concerns of the commenters. Section 98.34 of the final rule clarifies that for units and processes that use an orifice, nozzle, or venturi meter and operate continuously with infrequent outages, the owner or operator may postpone the initial calibration or PEI (as applicable) until the next scheduled maintenance outage, and may similarly postpone the subsequent recalibrations and PEIs."

Commenter Name: Ron Downey
Commenter Affiliation: LWB Refractories
Document Control Number: EPA-HQ-OAR-2008-0508-0719.1
Comment Excerpt Number: 24

Comment: 40 C.F.R. 98.34(e)(1) specifies procedures for the initial certification of a CEMS. As the Proposed Rule is currently written, it appears that all procedures identified must be followed to initially certify a CEMS. Based on our May 14, conference call, only one of the listed procedures must be followed to initially certify a CEMS. NLA proposes that 40 C.F.R. 98.34(e)(1) be revised to state that "For initial certification, use one of the following procedures:"

Response: EPA agrees that the proposed language could be confusing, and has added language to the final rule to clarify that any one of the alternate initial certification procedures for CO_2 CEMS is acceptable.

Commenter Name: J. P. Blackford
Commenter Affiliation: American Public Power Association (APPA)
Document Control Number: EPA-HQ-OAR-2008-0508-0661.1
Comment Excerpt Number: 10

Comment: APPA has concerns about the sampling requirements in the Proposed Rule for gaseous fuels other than natural gas. The daily carbon content sampling requirement seems overly onerous and it is recommended that sampling requirements for these fuels be required monthly, consistent with requirements for other fuels. APPA is concerned that a daily sampling requirement could discourage the use of landfill gas a co-fire fuel within an existing natural gas fired plant. Many times these projects have been marginal in the past, and additional regulatory barriers can discourage innovation. A further concern is that the monthly sampling for other fuel types might not provide any additional information to EPA. Some of the units operated by APPA member utilities are utilized as peaking units and as such may not operate often, therefore, monthly analysis would not be practical and overly burdensome. Many of our member utilities receive fuel shipments less frequently than monthly, so it serves little purpose to require them to sample fuel which will have the identical composition to the fuel that was sampled the previous month since no new fuel was delivered. APPA also believes that the carbon content in the fuel will have minimal variation from delivery to delivery thus minimizing the increase in accuracy gained by requiring monthly sampling. APPA recommends that EPA lower the requirement for sampling non-gaseous fuels to new deliveries rather than monthly in order to pinpoint the onset of fuel parameter variations.

Response: EPA acknowledges the commenter's concerns. Large units burning natural gas or distillate oil may not use Tier 2 instead of Tier 3. Section 98.34 has been revised to require that natural gas be sampled semiannually and, for other gaseous fuels, the daily sampling requirement has been retained, but only for facilities with existing equipment in place that is capable of providing the data. Otherwise, weekly sampling is required, which may be postponed in favor of monthly sampling until 2011 if new equipment must be purchased or if existing equipment must be upgraded to meet the weekly sampling and analysis requirements. CO_2 emissions from landfill gas (biogas or captured methane) may be calculated using Tier 1, and default factors for biogas has been added to Table C-2.

In addition, §98.34 has been revised for fuel oil and coal, such that a representative sampling is required for each fuel lot, i.e., for each shipment or delivery. For other liquid fuels and biogas, quarterly sampling is required. For other solid fuels, excluding municipal solid waste, weekly composite sampling with monthly analysis is required.
The final rule clarifies that fuel sampling and analysis data provided by the supplier may be used in the emission calculations, and that fuel billing meters may be used to quantify fuel consumption. To simplify the emission calculations in Tiers 2 and 3, averaging of HHV and carbon content data is permitted if these data are obtained at least at the minimum frequency specified in §98.34. If the results of fuel sampling are received monthly or more frequently, the weighted annual average high heat value shall be calculated using Equation C-2b. If the results of fuel sampling are received less frequently than monthly, then the annual average HHV shall be calculated using the arithmetic average HHV for all valid samples for the year. However, regardless of the sampling frequency, the owner or operator must use the results of all available valid fuel analyses in the emissions calculations.

Commenter Name: Robert D. Bessette
Commenter Affiliation: The Council of Industrial Boiler Owners (CIBO).
Document Control Number: EPA-HQ-OAR-2008-0508-0513.1
Comment Excerpt Number: 36

Comment: The requirements in §98.34, Monitoring and QA/QC, should be modified to provide flexibility by allowing use of site specific fuel analysis values that would be more representative of fuels combusted than the default values. Those site specific values could be available from site samples and analyses or from supplier provided analyses on some frequency that is less frequent than monthly.

Response: EPA has revised §98.34 to clarify that only the methods listed in that section may be used for fuel sampling and analysis for Tiers 2 and 3, regardless of any other methods that are incorporated in §98.7. The Agency believes that the methods listed in §98.34 of the final rule, derived from §98.7, provide operators adequate flexibility for best practices.

Commenter Name: Robert D. Bessette
Commenter Affiliation: The Council of Industrial Boiler Owners (CIBO).
Document Control Number: EPA-HQ-OAR-2008-0508-0513.1
Comment Excerpt Number: 37

Comment: In §98.34(d)(3), combustion of gaseous fuels other than natural gas (e.g., refinery gas, or process gas) needs to use Tier 3 unless a CEMS is used for Tier 4. This paragraph indicates (as does the Preamble at 16484) that daily sampling and analysis is required to determine carbon content and molecular weight of the fuel. The Preamble notes that "The daily fuel sampling requirement for units that combust 'other' gaseous fuels would likely not be overly burdensome, because the types of facilities that burn these fuels are likely to have equipment

(e.g., on-line gas chromatographs) to continuously monitor the fuels' characteristics in order to optimize process operation." 74 FR 16484. While this is the case for some particular off-gas streams, it is definitely not the case for all process gases, and those with monitoring might require considerable cost to upgrade for this purpose. This requirement could impose an exorbitant and totally unjustified cost on facilities.
If such sampling and analytical equipment is not installed, it should be acceptable to use typical analytical or engineering data to determine the analysis. Additionally, if a process gas stream contains less than 25% carbon by weight as demonstrated by engineering or model analysis, that initial demonstrated value should be considered adequate for ongoing emissions determinations. Moreover, if the process gas stream does not contain significant carbon content (< 10% by weight), there should be no need for any reporting for those process gas streams providing documentation is retained supporting that position.

Response: EPA acknowledges and appreciates the commenter's concerns. In the final rule concerning other gaseous fuels, §98.34 has been revised to retain the daily sampling requirement, but only for facilities with existing equipment in place that is capable of providing the data. Otherwise, weekly sampling is required, which may be postponed in favor of monthly sampling until 2011 if new equipment must be purchased or if existing equipment must be upgraded to meet the weekly sampling and analysis requirements.

In addition, the final rule clarifies that fuel sampling and analysis data provided by the supplier may be used in the emission calculations, and that fuel billing meters may be used to quantify fuel consumption. To simplify the emission calculations in Tiers 2 and 3, averaging of HHV and carbon content data is permitted if these data are obtained at least at the minimum frequency specified in §98.34. If the results of fuel sampling are received monthly or more frequently, the weighted annual average high heat value shall be calculated using Equation C-2b. If the results of fuel sampling are received less frequently than monthly, then the annual average HHV shall be calculated using the arithmetic average HHV for all valid samples for the year. However, regardless of the sampling frequency, the owner or operator must use the results of all available valid fuel analyses in the emissions calculations.

Commenter Name: Burl Ackerman
Commenter Affiliation: J. R. Simplot Company
Document Control Number: EPA-HQ-OAR-2008-0508-1641
Comment Excerpt Number: 14

Comment: The rule requires periodic on-site sampling and analysis of fuels. We recommend requiring fuel suppliers perform the analysis and provide individual sources the required information on billing statements, rather than having every individual source performing the same analysis on the same fuel.

Response: Though EPA has not required fuel suppliers to provide fuel analysis data to customers, the final rule clarifies that fuel sampling and analysis data provided by the supplier may be used in the Subpart C emission calculations. Subpart KK, Suppliers of Coal, has not been included in this final rule. Subpart MM, Suppliers of Petroleum Products, and Subpart NN, Suppliers of Natural Gas, provide upstream reporters with the option of using default HHV and carbon contents or site specific sampling. EPA has not required fuel suppliers to provide HHV data to facilities, as provision of this type of information is typically addressed in private sector purchase contracts.

Commenter Name: Steven J. Rowlan
Commenter Affiliation: Nucor Corporation (Nucor)
Document Control Number: EPA-HQ-OAR-2008-0508-0605.1
Comment Excerpt Number: 45

Comment: In 98.34(a), the term "detailed explanation" should be left out. The documents should show how the calculations are made.

Response: EPA has revised the final rule, and now in §98.34(e) requires an "explanation" when requested, and also requires "sufficient" data for emission verification**.** EPA believes that it is appropriate to require reporters to retain records containing an explanation of how company records are used to estimate fuel consumption, sorbent usage, and/or quantity of steam generated. EPA expects that an explanation of how company records are used to estimate these parameters would show how the relevant calculations are made.

Commenter Name: Steven J. Rowlan
Commenter Affiliation: Nucor Corporation (Nucor)
Document Control Number: EPA-HQ-OAR-2008-0508-0605.1
Comment Excerpt Number: 46

Comment: In 98.34(b), Most sources, particularly smaller sources, will have no capability of explaining the "technical basis" for estimated accuracy statements, but must simply rely upon the manufacturer's or calibrator's statement. It is not clear why EPA would need more.
Response: EPA refers commenter to §98.34(g) where the final text describing this requirement appears. As described, the GHG Monitoring Plan required under §98.3(g)(5) must document the procedures used to ensure the accuracy of the parameters used to quantify emissions (e.g., fuel usage, steam production, etc.). EPA believes it is appropriate to require reporters to document the technical basis for the estimated accuracy of measurements, and has retained this requirement in the final rule as described in this section.

Commenter Name: Steven J. Rowlan
Commenter Affiliation: Nucor Corporation (Nucor)
Document Control Number: EPA-HQ-OAR-2008-0508-0605.1
Comment Excerpt Number: 47

Comment: Section 98.34(d)(1) should provide an allowance for replacement as well as recalibration.

Response: EPA does not believe that any further language is necessary to clarify that fuel flow meters may be replaced, so long as the replacement meter is calibrated according to the specifications of the rule.

Commenter Name: Sarah E. Amick
Commenter Affiliation: The Rubber Manufacturers Association (RMA)
Document Control Number: EPA-HQ-OAR-2008-0508-0647.1
Comment Excerpt Number: 12

Comment: RMA recommends that the greenhouse gas emission factors utilized in the proposed rule be consistent with the factors used by the World Business Council for Sustainable Development (WBCSD) and in congressional legislation. Currently, the proposed rule uses different methods for calculating greenhouse gas emissions than the method used by the World Business Council. (See Table 1 in DCN:EPA-HQ-OAR-2008-0508-0647.1) Because greenhouse gas emissions are a global issue, we support consistency in the emission factors and methods that are used in all U.S. greenhouse gas regulations. As global companies, RMA member companies, particularly in the tire industry, utilize the international greenhouse gas emission factors as established by the WBCSD to report GHG emissions from facilities corporate-wide. Since greenhouse gas emissions are a global issue, it is important for companies and governments to be able to compare data and track progress across different geographic regions. Without a single, unified set of emission factors, data reported under different reporting requirements would not be comparable and would not be appropriately used to establish trends or benchmark progress globally. Since global companies already use WBCSD emission factors successfully to calculate and report GHG emissions, we recommend that all data collected prior to congressional legislation should be calculated based on the WBCSD emission factors. We understand that pending legislation also provides GHG emission factors. While outside the scope of this NPRM, RMA also supports the use of the WBCSD emission factors in the legislative context. [See DCN:EPA-HQ-OAR-2008-0508-0647.1 for table showing Examples of differences between the NPRM and the World Business Council Emissions Factors]

Response: EPA is not aware of pending legislation that has emission factors for unit-level reporting of greenhouse gas emission. Additionally, EPA can not consider detailed data in specific pieces of draft legislation as the requirements may change if and when bills are passed by Congress and signed into law by the President. EPA does not agree that there should be a single unified set of emission factors across all reporting programs because the legal foundation and policy goals of programs differ, particularly across regions and countries. Nevertheless, EPA has extensively reviewed the default emission factors and high heat values provided in Subpart C of the final rule, and believes that they are appropriate and, to the extent possible, consistent with those used in other programs. Please see the Technical Support Document for Subpart C.

Commenter Name: Rich Raiders
Commenter Affiliation: Arkema Inc.
Document Control Number: EPA-HQ-OAR-2008-0508-0511.1
Comment Excerpt Number: 33

Comment: EPA should add language to Subpart C of Part 98 to add the appropriate language to address regulatory overlaps with any 40 CFR 63 Subpart including performance test monitoring verification plans, site-specific monitoring plans, and precompliance reports. This section should specify that the specific MACT-required monitoring provisions override Part 98, as approved by the appropriate permitting authority. EPA correctly limited the applicability of the proposed Part 98 to those regulations requiring compliance with 40 CFR 60.13(a)(2), 61.14(a)(2), and 63.8(a)(2). EPA should clarify that the potential applicability to the proposed 40 CFR 63 Subpart SS modifications in this proposal conforms to the intent shown in Tables 1 and 2 of the proposal preamble. Arkema recognizes that, in December 2008, the District of Columbia Court of Appeals has vacated the MACT startup, shutdown, and malfunction program in 40 CFR 63. The entire concept of how facilities manage process upsets, breakdowns, and equipment failures with the MACT program is currently in flux. EPA should await further developments in this litigation and coordinate this rule with the agency's next steps to manage the ongoing litigation response. Many of the process units that will become subject to Part 98 already comply with CAM, and others comply with one or more MACT standards described above. Instead of EPA promulgating subpart-by-subpart data handling provisions in Part 98, EPA should, as a Part 98 general provision, require that regulated entities either utilize the MACT missing data approach in 40 CFR 63 Subpart SS, the CAM data management approach at 40 CFR 64, comply with a streamlined Part 98-specific approach, or provide a site-specific precompliance report described next, as the facility's data management approach. As some units may fall under different portions of this analysis, a reporter could use missing data approaches including one or all of these methods.

Response: The commenters statement that "EPA correctly limited the applicability of the proposed Part 98 to those regulations requiring compliance with 40 CFR 60.13(a)(2), 61.14(a)(2), and 63.8(a)(2)" is not correct.

EPA appreciates the comment, though EPA's approach makes use of existing data and methodologies to the extent feasible, and is consistent with the types of methods contained in other GHG reporting programs (e.g., the California mandatory reporting rule, WCI, RGGI, TCR, and Climate Leaders). It is also noted that MACT does not measure GHG emissions and, unlike the GHG reporting rule which is focused on collecting information on GHG emissions, the MACT program is a compliance program aimed to meet specific emission limits for toxic air pollutants.

Commenter Name: Karen St. John
Commenter Affiliation: BP America Inc. (BP)
Document Control Number: EPA-HQ-OAR-2008-0508-0631.1
Comment Excerpt Number: 66

Comment: Section 98.34(d)(1) of Subpart C, Section 98.254(a) of Subpart Y, and elsewhere through out the monitoring and QA/QC requirements of the proposed rule states flow meters would have to be calibrated by January 1, 2010. This requirement is technically impossible to meet due to the number of flow meters at facilities, coupled with the projected finalization of the reporting rule in November of 2009. Also, some instrumentation may require maintenance that prevents calibration, where such maintenance cannot be conducted until a shutdown. BP does not believe EPA would or should require a shutdown of a facility to calibrate these instruments. For meters and instrumentation which cannot be calibrated or verified without a facility or unit shut-down, BP requests an exemption from a calibration compliance date and a provision for them to be calibrated or verified during the next scheduled turn around using good manufacturing practices.

Response: See the response to comment EPA-HQ-OAR-2008-0508-1142.1 excerpt 26 for information on additional flexibility provided for 2010. The commenter should refer to §98.3 of the final rule for calibration procedures required under the rule. Per this section, flow meters measuring data used to calculate emissions shall be calibrated prior to April 1, 2010 using procedures specified in the section. For the continuously-operating units and processes described in §98.34, the required flow meter and PEI recalibrations may be postponed until the next scheduled maintenance outage.

7. PROCEDURES FOR ESTIMATING MISSING DATA

Commenter Name: Lorraine Krupa Gershman
Commenter Affiliation: American Chemistry Council (ACC)
Document Control Number: EPA-HQ-OAR-2008-0508-0423.2
Comment Excerpt Number: 67

Comment: We recommend that EPA modify §98.35 to allow the ³best available estimate´ method of §98.35(2) to be available for all parameters including those listed in §98.35(1), not just the limited parameters listed in §98.35(2), if the owner or operator can justify using it based on process or operating knowledge. There may be times when the arithmetic averaging method does not yield an appropriate result, given variations in operating conditions.

Response: See the Preamble, Section III. C., for the response on Procedures for Estimating Missing Data.

EPA believes that the missing data substitution procedures discussed in detail in §98.35(b) of the final rule have been simplified. Revisions to §98.35(b)(1) limit the requirement of using the "before and after" average for substitute data to three parameters, i.e., fuel, carbon content, and molecular weight. If the "after" value is not yet available when the GHG emissions report is due, the "before" value may be used for missing data substitution. For all other parameters, the substitute data values are the best available estimates, based on all available process information. EPA has determined that this additional flexibility allows for the use of the "best available estimate" method for missing data substitution for all appropriate parameters and yields the most accurate results for the purposes of substituting missing data under Part 98.

Commenter Name: Lloyd Stone
Commenter Affiliation: Westlake Chemical Corporation
Document Control Number: EPA-HQ-OAR-2008-0508-0442.1
Comment Excerpt Number: 7

Comment: Are there potential penalties for missing data? The missing data substitution requirements in §98.35 are prescriptive and are not always consistent with the design of many existing CEMS installations. Westlake has facilities that are subject to NSPS requirements that only require collection of valid data for a specified percentage of the facility operating hours. The NSPS standards do not impose substitution requirements for missing data, and neither should this rule.

Response: See the Preamble, Section II. O., for the response on the relationship of this rule to other programs.

Please see Preamble Sections II. L. and VI. and response to comments documents "Approach to Verification and Missing Data" and "Compliance and Enforcement" for more information about EPA's missing data requirements and approach to compliance and enforcement.
The substitution requirements discussed in detail in §98.35 have been simplified in the final rule for all units that are not subject to the requirements of the Acid Rain Program. First, revisions to

§98.35(b)(1) limit the use of the "before and after" average for substitute data to three parameters, i.e., fuel HHV, carbon content, and molecular weight. If the "after" value is not yet available when the GHG emissions report is due, the "before" value may be used for missing data substitution. For all other parameters, the substitute data values are the best available estimates, based on all available process information. EPA believes that the provisions for estimating missing data in the final rule will yield the appropriate results without imposing excessive financial burdens.

Commenter Name: Janice Adair
Commenter Affiliation: Western Climate Initiative (WCI)
Document Control Number: EPA-HQ-OAR-2008-0508-0443.1
Comment Excerpt Number: 12

Comment: WCI recommends that the reporting rule include a provision for minimum data collection and procedures for approving interim data collection during equipment breakdowns at general stationary fuel combustion sources. The proposed rule would require the reporter to document and keep record of the procedures used to determine the appropriate substitute data values. However, it does not appear to provide an acceptable limit for missing fuel analytical or direct measurement data. A potentially very significant percentage of required data might be declared "missing" and replaced with questionable data. A regulatory incentive to limit missing data is needed. We agree that the accuracy of an emissions data set is important.

Response: See the individual source category section(s) of the Preamble and the source category comment response document(s) for the response on the source category-specific monitoring and reporting requirements.

EPA has not included a specific limit for missing fuel analytical or direct measurement data because the Clean Air Act already provides avenues for enforcement, and provides EPA some discretion in working with facilities that have difficulty complying with the provisions of the rule. Please see Preamble Sections II. L., and VI. and response to comments documents "Approach to Verification and Missing Data" and "Compliance and Enforcement" for more information about EPA's missing data requirements and approach to compliance and enforcement.

Commenter Name: Stephen E. Woock
Commenter Affiliation: Weyerhaeuser Company
Document Control Number: EPA-HQ-OAR-2008-0508-0451.1
Comment Excerpt Number: 13

Comment: Weyerhaeuser agrees with and supports EPA's proposed approach at §98.35 to handle missing data. Missing data is the use of substitute data whenever a quality assured value of a parameter that is used to calculate GHG emissions is unavailable. Weyerhaeuser agrees it is important to have missing data procedures to ensure a complete and accurate report of emissions. For units using the CO_2 calculation methodologies in Tiers 2 and 3, when Higher Heating Value (HHV), fuel carbon content, or fuel usage data are missing, EPA proposes the substitute data value would be the average of the quality-assured values of the parameter immediately before and immediately after the missing data period. When Tier 3 or Tier 4 is used and fuel flow rate or stack gas flow rate data is missing, the substitute data values would be the best available estimates of these parameters, based on process and operating data (e.g., production rate, load, unit operating time, etc.). Using the data before and after the missing data event represents the most accurate, statistically sound and representative approach to estimating this missing data.

Response: EPA appreciates the commenter's input regarding the missing data substitution procedures in §98.35, which have been clarified and simplified in the final rule.

Commenter Name: Paul R. Pike
Commenter Affiliation: Ameren Corporation
Document Control Number: EPA-HQ-OAR-2008-0508-0487.1
Comment Excerpt Number: 15

Comment: Part 75 missing data procedures become increasingly more conservative based on the length of the missing data period and the overall data availability in the prior year (or since certification of the monitoring system). When significant amounts of data are declared "invalid" under Part 75, the procedure can require substitution of "maximum potential" values that may have little or no relationship to actual values. This most often occurs when a source discovers (usually as a result of a self-audit) long after a test was performed, or was due, that the test result was in error or that the test was not performed. In such cases, use of missing data procedures may not be the best estimate of actual emissions. EPA should allow the use of procedures like those provided for other stationary combustion units under proposed §98.35 when Part 75 missing data procedures become overly conservative or punitive. We suggest the addition of a new section that provides for reporting of cumulative CO_2 emissions based on data reported under §75.64, with the exception that the procedures in §98.35(b) may be used to substitute for missing data whenever data availability falls below 90 percent as calculated under §75.32, or whenever the Part 75 procedures call for use of a "maximum" or "maximum potential" value.

Response: See the Preamble, Section II. L., for EPA's response to comments on estimating missing data.

Nearly all Part 75 sources maintain very high monitor data availability (95 percent or better) and use very little substitute data. Only when the data availability drops below 80 percent (which very seldom occurs) are the substitute data values significantly higher than the true CO_2 concentrations. In response to the comments, the Agency believes that the potential bias in existing Part 75 methods based on data availability is acceptable versus the complexity of having Acid Rain Program EGUs calculate two different sets of CO_2 emissions data based on different missing data routines. Also, because data availability in the Acid Rain Program is very high, over reporting due to data substitution will be minimal, and not at a level that would warrant requiring all Acid Rain Program sources to prepare, record, and report two sets of missing data calculations. Therefore, sources that monitor CO_2 emissions according to Part 75 should continue to use the standard Part 75 missing data provisions, and no adjustments to these substitute data values are deemed necessary for Part 98 reporting purposes.

Commenter Name: Angela Burckhalter
Commenter Affiliation: Oklahoma Independent Petroleum Association (OIPA)
Document Control Number: EPA-HQ-OAR-2008-0508-0386.1
Comment Excerpt Number: 18

Comment: EPA proposes that within 7 days of receipt of written request (e.g., a request by electronic mail) from the EPA or applicable State or local air pollution control agency, the owner or operator shall submit calculation methodologies and documents that ensure the accuracy of the data. Company personnel may be on vacation, sick or other types of leave that would prevent a company from responding within 7 days. This is too short a time frame. Reporting entities should have at least 30 days to respond. In addition, the request should also be sent to the company in the form of a formal letter sent in the mail.

Response: EPA acknowledges the commenter's concerns. In §98.36(e)(3) of the final rule, EPA has allowed owners or operators 30 days from receipt of a written request for information to respond to that request.

EPA does not believe that it is necessary to specify that requests for data submissions be made via hard copy mail. EPA believes that electronic requests are sufficiently reliable.

Commenter Name: Robert P. Strieter
Commenter Affiliation: The Aluminum Association
Document Control Number: EPA-HQ–OAR-2008-0508-0350.1
Comment Excerpt Number: 5

Comment: Section 98.35 of the proposed rule outlines reporting requirements for missing data, such as during continuous emission monitor system (CEMS) malfunction or missing fuel samples, whereby substitute data are used. The approach proposed includes some criteria related to facilities currently regulated under the Acid Rain Program and thereby applicable in general only to electric utilities. The rest of the criteria are for a short list of relevant sources and categories of reporting information that is deficient in scope and is unclear. We recommend that the proposal be revised to incorporate existing missing data methods included under current Clean Air Act programs such as for the Title V permitting and reporting program. Facilities would then follow existing procedures included in their respective permitting provisions to provide missing data.

Response: See the Preamble, Section II. O., for the response on the relationship of this rule to other programs.

EPA acknowledges the concerns of the commenters. Section 98.35(a) has been revised to add flexibility and to simplify the missing data substitution procedures for units that use the Tier 1, Tier 2, Tier 3, and Tier 4 Calculation Methodologies. In response to the comment, all relevant reporting programs were considered in the development of this rule, and the approach selected was based on balancing data accuracy and cost for the facilities subject to these requirements. The use of existing data and methodologies was incorporated to the extent feasible to achieve the intended purpose of this rule, as discussed in detail in the Preamble. The source category-specific reporting requirements and methodologies for calculating substitute data values, as applicable, for each source category are addressed in the appropriate subpart.

Commenter Name: Paul L. Carpinone
Commenter Affiliation: Tampa Electric Company (TECO)
Document Control Number: EPA-HQ-OAR-2008-0508-0717.1
Comment Excerpt Number: 11

Comment: Tampa Electric agrees with the EPA's decision that over conservative missing data procedures are inappropriate because they could result in significant overestimation of GHG emissions. Thus, Tampa Electric supports EPA's proposal methods for determining substitute data values previously mentioned in Subpart C.

Response: EPA appreciates the commenter's input regarding the missing data substitution procedures for Subpart C in §98.35, which have been clarified and simplified in the final rule.

Commenter Name: See Table 6
Commenter Affiliation:
Document Control Number: EPA-HQ-OAR-2008-0508-0679.1
Comment Excerpt Number: 114

Comment: §98.37. References to §98.35(a)(1) and §98.35(a)(4) should be changed to §98.35, as §98.35(a) does not have subdivisions.

Response: EPA has corrected this error. Section 98.37 now refers to §98.35(b).

Commenter Name: Robbie LaBorde
Commenter Affiliation: CLECO Corporation (CLECO)
Document Control Number: EPA-HQ-OAR-2008-0508-1566
Comment Excerpt Number: 6

Comment: In Subpart D, section 98.45 of MRGG, under the title of Procedures for Estimating Missing Data, it is required that electrical generating units subject to the Acid Rain Program use missing data substitution procedures in 40 CFR Part 75. This is a conservative missing data substitution procedure and was intended to insure that SO_2 emissions were not under-reported. Cleco does not feel that such conservative SO_2-based procedures are appropriate for CO_2 emission calculations. In that program, if CEMS data is missing, data is substituted on a sliding scale based on monitor data availability and is appropriate where hourly SO_2 emissions could be variable. However, this method is not necessary for CO_2 emissions where hourly variation is not significant. In addition, assuming that MRGG might some day be used in an allowance trading program, the high bias that would result from the conservative Part 75 data substitution methods for calculating CO_2 emissions would be significantly more costly than the overestimation of SO_2 emissions. Therefore, EPA should adopt data substitution procedures for acid rain affected units that are more appropriate for CO_2 emissions. For instance, EPA is urged to allow the option of use of data substitution procedures under Subpart D that are similar to those required under Subpart C of MRGG. Also, it is recommended that the Agency allow for acid rain affected units the option to use fuel consumption data to estimate missing data for longer time periods. For example, since there is limited variability in the carbon content of coal, a facility could be allowed to calculate CO_2 emissions based on carbon content measurements and the amount of fuel burned.

Response: As stated in the Preamble, Section III. C., EPA does not agree that the substitute data procedures in Part 75 are too conservative. Nearly all Part 75 sources maintain very high monitor data availability (95 percent or better) and use very little substitute data. Only when data availability drops below 80 percent (which seldom occurs) are the substitute data values significantly higher than the true CO_2 concentrations. Therefore, the Agency believes that the potential for bias in the Part 75 CO_2 data is very small. It is vastly preferable for Acid Rain Program EGUs to calculate and report CO_2 emissions in a consistent manner, rather than having them report two different sets of CO_2 emissions data based on different missing data routines. Sources that monitor CO_2 emissions according to Part 75 should continue to use standard Part 75 missing data provisions, and no adjustments to these substitute data values are deemed necessary for Part 98 reporting purposes.

Commenter Name: Renae Schmidt
Commenter Affiliation: CITGO Petroleum Corporation
Document Control Number: EPA-HQ-OAR-2008-0508-0726.1
Comment Excerpt Number: 13

Comment: CITGO agrees that for missing flow rate records, the substitute value should be the best available estimate based on available process data or on the arithmetic average of the parameter immediately preceding and immediately following the missing data.

Response: EPA appreciates the commenter's input regarding the missing data substitution procedures in §98.35, which have been clarified and simplified in the final rule.

Commenter Name: See Table 3
Commenter Affiliation:
Document Control Number: EPA-HQ-OAR-2008-0508-0433.2
Comment Excerpt Number: 22

Comment: The missing data substitution requirements of the proposed rule at §98.35 are prescriptive and are not always consistent with the design of many existing CEMs installations. For facilities subject to 40 CFR part 75 requirements, this requirement is generally consistent with that regulation. However, numerous other EPA requirements that mandate the use of CEMs systems require collection of valid data only for a specified percentage of the facility operating hours. These CEMs, typically required by NSPS, do not impose substitution requirements for missing data. Therefore, the owners of many of these CEMs installations that become subject to these proposed rules, including most of those in petroleum refineries, will be required to upgrade the data processing software for each CEMs unit in order to implement the specified data substitution procedures. This upgrade is often not a trivial matter, because these software packages are usually highly customized to each source and the associated permit and regulatory reporting requirements. In some cases, making this change to the data processing procedures in order to implement the missing data substitution requirements of proposed part 98 could require purchase and installation of a completely new data processing system at a cost far exceeding the estimated facility costs to comply. Therefore, installation of CEMs should be at the discretion of each company.

Response: EPA disagrees with the commenter's proposal that installation of CEMs should be at the discretion of each company. See the Preamble, Section II. L., for the response on the general monitoring approach, and Preamble, Section II. C., for additional information on the applicability of Tiers.

See the Preamble, Section II. O., for the response on the relationship of this rule to other programs. See the individual source category section(s) of the Preamble and the source category comment response document(s) for the response on source category-specific reporting requirements in Subparts C through PP.

EPA acknowledges the concerns of the commenters and agrees that upgrading data processing software solely for the purposes of obtaining substitute values for missing data would be unduly burdensome. However, for this mandatory GHG reporting program, the Agency concluded that provisions for missing data procedures are necessary in order to ensure there is a complete report of emissions from a particular facility. The substitution requirements discussed in detail in §98.35 have been simplified in the final rule for all units that are not subject to the requirements of the Acid Rain Program. First, revisions to §98.35(b)(1) limit the use of the "before and after" average for substitute data to three parameters, i.e., fuel HHV, carbon content, and molecular weight. If the "after" value is not yet available when the GHG emissions report is due, the "before" value may be used for missing data substitution. For all other parameters, the substitute data values are the best available estimates, based on all available process information. EPA believes that the provisions for estimating missing data in the final rule will yield the appropriate results without imposing excessive financial burdens.

Commenter Name: Robert Rouse
Commenter Affiliation: The Dow Chemical Company
Document Control Number: EPA-HQ-OAR-2008-0508-0533.1
Comment Excerpt Number: 25

Comment: EPA Should Provide Additional Flexibility for Procedures for Estimating Missing Data. EPA should modify 98.35 to allow the "best available estimate" method in 98.35(b)(2) to be available for all parameters including the parameters listed in 98.35(b)(1), not just the limited parameters listed in 98.35(b)(2), if the owner or operator can justify using it based on process or operating knowledge. There may be times when the arithmetic averaging method does not yield an appropriate result, given variations in operating conditions.

Response: See the Preamble and Procedures for Estimating Missing Data section of the Preamble.

EPA has simplified the missing data substitution procedures discussed in detail in §98.35(b) of the final in a way that addresses the concerns raised by the commenter. Revisions to §98.35(b)(1) limit the requirement of using the "before and after" average for substitute data to three parameters, i.e., fuel, carbon content, and molecular weight. If the "after" value is not yet available when the GHG emissions report is due, the "before" value may be used for missing data substitution. For all other parameters, the substitute data values are the best available estimates, based on all available process information. EPA has determined that this additional flexibility allows for the use of the "best available estimate" method for missing data substitution for all appropriate parameters and yields the most accurate results for the purposes of substituting missing data under Part 98.

Commenter Name: Lauren E. Freeman
Commenter Affiliation: Hunton & Williams LLP
Document Control Number: EPA-HQ-OAR-2008-0508-0493.1
Comment Excerpt Number: 28

Comment: Although UARG also generally does not object to a rule that allows ARP affected sources to use Part 75 missing data provisions to report CO_2, there are some circumstances under which use of those procedures may not be appropriate. In order to create incentives for high data availability, Part 75 missing data procedures become increasingly conservative based on the length of the missing data period and the overall data availability in the prior year (or since certification of the monitoring system). See, e.g., 40 C.F.R. §§75.35 - 75.36 and Appendix D §2.4.2 (heat input). In cases where significant amounts of data are declared "invalid" under Part 75, the procedure can require substitution of "maximum potential" values that may have little or no relationship to actual values. This most often occurs when a source discovers (usually as a result of a self-audit) long after a test was performed, or was due, that the test result was in error or that the test was not performed. In such cases, use of missing data procedures may not be the best estimate of actual emissions. To make the CO_2 reporting requirements for EGUs more consistent with the reporting requirements for other sources, EPA should allow the use of procedures like those provided for other stationary combustion sources under proposed §98.35 when Part 75 missing data procedures become overly conservative or punitive. UARG does not believe it is reasonable to require Part 75 sources to report dramatically overstated emissions when other source categories, including stationary combustion sources, are not required to do so. To implement this concept, UARG suggests addition of a new section that provides for reporting of cumulative CO_2 emissions based on data reported under §75.64, with the exception that the procedures in §98.35(b) may be used to substitute for missing data whenever monitor data availability calculated under Part 75 falls below 90 percent as calculated under §75.32, or whenever the Part 75 procedures call for use of a "maximum" or "maximum potential" value.

Response: See the Preamble, Section III. C., the Subpart D comment response document volume, and the response to comment EPA-HQ-OAR-2008-0508-0956.1 excerpt 20 for the rationale for using substitute data reported under Part 75.

Part 75 missing data procedures are designed to provide conservatively high substitute data values, to ensure that emissions are not underestimated during monitor outages. The missing data algorithms also become increasingly conservative (biased towards higher emissions) as monitor downtime increases, so that sources have an incentive to maintain high data availability. Nearly all Part 75 sources maintain very high monitor data availability (95 percent or better) and use very little substitute data. Only when the data availability drops below 80 percent (which very seldom occurs) are the substitute data values significantly higher than the true CO_2 concentrations. Therefore, the Agency believes that the potential for bias in the Part 75 CO_2 data is very small. It is vastly preferable for Acid Rain Program EGUs to calculate and report CO_2 emissions in a consistent manner, rather than having them report two different sets of CO_2 emissions data based on different missing data routines. Sources that monitor CO_2 emissions according to Part 75 should continue to use the standard Part 75 missing data provisions, and no adjustments to these substitute data values are deemed necessary for Part 98 reporting purposes.

Commenter Name: See Table 6
Commenter Affiliation:
Document Control Number: EPA-HQ-OAR-2008-0508-0679.1
Comment Excerpt Number: 113

Comment: [Page 16637] Sec. 98.35 Procedures for estimating missing data. API offers the following revised language for this section's paragraph (b) at this time. (b) For all units that are not subject to the requirements of the Acid Rain Program, when the Tier 1, Tier 2, Tier 3, or Tier 4 calculation is used, perform missing data substitution as follows for each parameter: (1) For each missing value of the heat content, carbon content, or molecular weight of the fuel, and for each missing value of CO_2 concentration and percent moisture, the substitute data value shall be the quality-assured value of that parameter immediately preceding the missing data incident. If the quality assured value immediately following the missing data incident is different by more than ten percent of the preceding value, the arithmetic average of the quality-assured values of that parameter immediately preceding and immediately following the missing data incident, shall be used. If, for a particular parameter, no quality-assured data are available prior to the missing data incident, the substitute data value shall be the first quality-assured value obtained after the missing data period. (2) For missing records of stack gas flow rate, fuel usage, and sorbent usage, the substitute data value shall be the best available estimate of the flow rate, fuel usage, or sorbent consumption, based on all available process data (e.g., steam production, electrical load, and operating hours). The owner or operator shall document and keep records of the procedures used for all such estimates.

Response: See the Preamble, Section III. C., for EPA's response on estimating missing data.

EPA believes that the missing data substitution procedures discussed in detail in §98.35(b) of the final rule have been simplified in a way largely consistent with the approach suggested by the commenter. Revisions to §98.35(b)(1) limit the requirement of using the "before and after" average for substitute data to three parameters, i.e., fuel HHV, carbon content, and molecular weight. If the "after" value is not yet available when the GHG emissions report is due, the "before" value may be used for missing data substitution. For all other parameters, the substitute data values are the best available estimates, based on all available process information. EPA has determined that this additional flexibility allows for the use of the "best available estimate" method for missing data substitution for all appropriate parameters and yields the most accurate results for the purposes of substituting missing data under Part 98.

Commenter Name: See Table 4
Commenter Affiliation:
Document Control Number: EPA-HQ-OAR-2008-0508-0455.1
Comment Excerpt Number: 20

Comment: Under Subpart C of the Proposal, stationary fuel combustion sources would be required to use substitute data whenever a quality-assured value of a parameter that is used to calculate GHG emissions is unavailable. The Class of '85 supports the Agency's proposed methods for determining substitute data values under Subpart C of the Proposal. Specifically, the Group agrees with EPA's decision that more conservative missing data procedures are inappropriate because they could result in significant overestimation of GHG emissions. Further, the Group believes that the Agency should consider using fuel consumption data as a data substitution method when data is missing over longer periods of time.

Response: EPA appreciates the commenter's input regarding the missing data substitution procedures in §98.35, which have been clarified and simplified in the final rule.

Commenter Name: Robert D. Bessette
Commenter Affiliation: The Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2008-0508-0513.1
Comment Excerpt Number: 48

Comment: There are missing data substitution requirements in the rule, however, there are no data substitution requirements for industrial source CEMS, under Part 60, not Part 75. If EPA wants data substitution, CIBO recommends use of emission factors as an alternative to the proposed methods.

Response: See the Preamble, Section III. C., for EPA's response on estimating missing data.

EPA disagrees with the suggestion that emission factors be used for estimating missing data. The missing data substitution procedures in §98.35, which have been clarified and simplified in the final rule, would involve substituting just the missing values needed for Tier 4 rather than a wholesale change in the methodology to an emission factor approach. This approach simplifies EPA verification and provides for the minimal amount of substitute data. Additionally, The NSPS monitoring does not specify substitute data in the same way as Part 75.

8. DATA REPORTING REQUIREMENTS

Commenter Name: Keith Adams
Commenter Affiliation: Air Products and Chemicals, Inc.
Document Control Number: EPA-HQ-OAR-2008-0508-1142.1
Comment Excerpt Number: 32

Comment: The proposed rule appears to require the source report its CEM S relative accuracy test audit (RATA) results. It is not clear if EPA would be satisfied by a singular statement that the CEMS passed or failed the RATA, or if the intent is to submit the entire RATA report which, in addition to being many pages in length, often contains confidential business information. Air Products Comment: Clarify that EPA does not want a source to submit its entire RATA report and instead, will be satisfied with a singular statement that the RATA was conducted (by whom and on what date) and the results of the RATA, as a pass/fail designation.

Response: EPA acknowledges the commenter's concerns, and has added additional language to §98.36(e)(2)(iv)(E) and (F), clarifying that reporters are required to submit the dates and *summarized* results of the QA tests (e.g., RATAs) performed during the reporting year. The rule does not require facilities to submit detailed test run information or hard copy test reports.

Commenter Name: Lorraine Krupa Gershman
Commenter Affiliation: American Chemistry Council (ACC)
Document Control Number: EPA-HQ-OAR-2008-0508-0423.2
Comment Excerpt Number: 74

Comment: In §98.36(d)(1)(iv)(F), reporting RATA results is also overly burdensome. At most, EPA should only require reporting the RATA as a pass/fail result. RATA results will need to be reported for some other regulatory requirement for which the CEMS was installed, so the additional reporting here is redundant. These reports will be available onsite in the records as a result of other regulation, so there is no need to report or collect as part of this effort. Other CEMS requirements do not require transmitting the RATA report, only to verify that the RATA was done.

Response: EPA acknowledges the commenter's concerns, and has added additional language to §98.36(e)(2)(iv)(E) and (F), clarifying that reporters are required to submit the dates and *summarized* results of the QA tests (e.g., RATAs) performed during the reporting year. The rule does not require facilities to submit detailed test run information or hard copy test reports.

Commenter Name: Linda Farrington
Commenter Affiliation: Eli Lilly and Company (Lilly)
Document Control Number: EPA-HQ-OAR-2008-0508-0680.1
Comment Excerpt Number: 23

Comment: While we agree that CO_2, CH_4, and N_2O should be included in the calculation of greenhouse gas emissions from the combustion of fossil fuels in boilers and generators, we question the increased reporting burden required by reporting these separately. Only CO_2e should be required to be reported. Additional calculations and fields will need to be included in EPA's electronic reporting software, resulting in additional complexity and an increased opportunity for data entry errors. Existing registries such as EPA Climate Leaders and Climate Registry require reporting of only CO_2e; separate reporting of other individual Kyoto Protocol gasses or additional global warming gasses is not required. Lilly recommends the EPA strive for consistency with these other programs by requiring affected facilities to report GHG emissions as CO_2e only.

Response: See the Preamble, Section II. O., for the response on the relationship of this rule to other programs.

EPA has decided to retain in the final rule the requirement to report CH_4 and N_2O from stationary combustion sources. Reporting of gases individually increases transparency, provides EPA information on the emissions of specific gases within and across industries that may have different mitigation approaches, provides researchers with needed information on the location of emissions of specific gases that is essential for determining actual radiative forcing, and provides overall transparency for the public. EPA's approach is consistent with other mandatory programs, including CARB, the EU ETS, in addition to UNFCCC reporting.

Commenter Name: Keith A. Nagel
Commenter Affiliation: ArcelorMittal USA and Severstal North America
Document Control Number: EPA-HQ-OAR-2008-0508-0496.1
Comment Excerpt Number: 27

Comment: The ability to report for multiple units by measuring fuel throughput at a common supply line under §98.36(c)(3) has particular potential to simplify reporting at complex facilities. However, one minor adjustment would greatly enhance the (already substantial) value of this alternative. As written, the common pipe approach assumes that all of the fuel transported will be combusted. That is not always the case, particularly at complex steelmaking facilities. For example, the ultimate common pipe for natural gas is the metered primary supply line where natural gas is transferred from the selling utility to a steel plant. Ideally, the throughput at that ultimate common pipe could be used to accurately determine CO_2 emissions by simple multiplication using the published combustion factors for natural gas. However, not all of that natural gas is combusted. Rather, a portion of that natural gas is added directly to blast furnaces as a process reactant. CO_2 emissions from the portion of the total natural gas supply that is used as an input to the steelmaking process will be separately measured as required by Subpart Q. Thus, presuming this natural gas was combusted as part of common pipe reporting would lead to double counting. This creates an obvious "catch 22": steel plants would be forced to choose between forgoing the most effective (utility meter) use of the common pipe rule or over-reporting GHG emissions. That problem has a simple solution. EPA can expand the utility of the common pipe rule by allowing sources to "deduct" properly metered amounts of fuel sent via common pipe which are not combusted. That minor adjustment would reduce the compliance burden substantially by allowing sources to move the common pipe location further upstream. At the same time, this change would increase the accuracy of emissions reporting by eliminating double counting. Similarly, sources should be allowed to deduct emissions associated with combustion sources that use a different reporting methodology. For example, we are evaluating use of the common pipe approach to aggregate the emissions associated with a variety of units that combust coke oven gas. The ideal common pipe location for calculating coke oven gas emissions would be immediately downstream of the coke plant, where coke oven gas is generated. That approach, however, would pose a double counting concern analogous to the one described above. For example, the sintering operation at ArcelorMittal's Burns Harbor facility combusts coke oven gas. To comply with Subpart Q at the sinter plant, ArcelorMittal is evaluating the potential installation of a CO_2 CEMS. Using the common pipe approach to coke oven gas combustion and a CO_2 CEMS at the sintering plant would cause Burns Harbor to report the CO_2 created from sintering coke oven gas combustion twice. As above, this inaccuracy can be corrected by simply allowing sources to deduct emissions covered under any alternate reporting approach from their common pipe numbers.

Response: See the Preamble, Section II. L., for the response on the general monitoring approach.

EPA acknowledges the commenter's concerns, and has addressed this issue in the final rule. Section 98.36(c)(3) states: If a portion of the fuel measured at the common pipe is diverted to a chemical or industrial process where it is used but not combusted, provided that the amount of fuel diverted is also measured with a calibrated flow meter, you may subtract out the diverted fuel from the fuel measured at the common pipe prior to performing the GHG emissions calculations."

Commenter Name: Leslie Bellas
Commenter Affiliation: National Lime Association (NLA)
Document Control Number: EPA-HQ-OAR-2008-0508-0520.1
Comment Excerpt Number: 28

Comment: Because lime plants typically do not generate steam, they cannot report steam generated from MSW combustion or the design rated steam output capacity, as required by 40 C.F.R. §98.36(d)(1)(ii)(F). Revise 40 C.F.R. §98.36(d)(1)(ii)(F) to apply only to those facilities that generate steam from MSW combustion.

Response: EPA has revised the rule so that Tier 1 may be used for a unit burning municipal solid waste that does not produce steam, provided that Tier 4 is not required. A default CO_2 emission factor and heat content for municipal solid waste has been added to Table C-1 for this purpose. Also in the final rule, you are to report CH_4 and N_2O emissions only for the combustion of fuels for which appropriate default emission factors are provided in Table C-2 (formerly C-3). Default factors for municipal solid waste are not provided in the revised Table C-2, therefore reporting of CH_4 and N_2O emissions is not required.

Commenter Name: Keith Adams
Commenter Affiliation: Air Products and Chemicals, Inc.
Document Control Number: EPA-HQ-OAR-2008-0508-1142.1
Comment Excerpt Number: 28

Comment: The proposed rule requires calculation and reporting of GHG emissions at the "unit-level" (unless the aggregation options of §98.36(c) are employed). Reporting emissions at the unit-level goes beyond the policy development intention of the reporting rule and increases the risk that confidential business information (operating rates, fuel choices, operating efficiencies) could be revealed in reports accessible to domestic and international competitors and customers of the regulated source. Air Products Comment: Emission reporting should be required at the facility-level only by source type. Reporting at the unit-level should not be required. Additionally, provisions to protect the confidentiality of all process, production and business-related information required under the rule should be strengthened. While Air Products accepts that facility-level emissions cannot be protected from public disclosure, it strongly requests all other information should, by default, be considered confidential business information and afforded the utmost protection from public disclosure.

Response: See the Preamble, Section II. R., for EPA's response on CBI.

See the Preamble and the response to comment EPA-HQ-OAR-2008-0508-0520.1 excerpt 16 for the rationale for the level of reporting and the additional flexibility provided to reporters, particularly for common pipe and aggregated unit circumstances.

Some potential programs under the Clean Air Act including NSPS, are applied at more disaggregated level than the overall facility. Because the main purpose of the rule is to collect information for climate policy development under the CAA, EPA views unit level reporting as appropriate. Additionally, EPA has decided to serve the role as verifier rather than require third-party verification. In view of this, additional unit-level information is deemed necessary to provide assurance that the reported facility-wide GHG emissions data are both credible and accurate.

Commenter Name: Keith A. Nagel
Commenter Affiliation: ArcelorMittal USA and Severstal North America
Document Control Number: EPA-HQ-OAR-2008-0508-0496.1
Comment Excerpt Number: 28

Comment: Section 98.36(c)(1) allows the aggregation of "two or more units" for reporting purposes but limits aggregation to sources with a "combined maximum rated heat input capacity of 250 mmBtu/hr or less." That 250 mmBtu/hr limit may be suitable for small facilities which have a limited number of small units to aggregate. However, it is not suitable for large, complex sources with many small sources that can be efficiently aggregated for reporting. Two promising alternatives would avoid imposing unnecessary additional burdens on large facilities. First, EPA could establish a tiered threshold for aggregation of small sources that adjusts with the size of the reporting facility. For example, sources with 25 units or fewer could have a 250 mmBtu/hr aggregation limit, sources with between 25 and 50 units could have a 500 mmBtu/hr aggregation limit, etc. Alternately, EPA could augment the current 250 mmBtu limit/hr by also allowing the unlimited aggregation of units that fall below a certain minimum size (e.g., 10 mmBtu). These alternatives would have no significant impact on the amount of emissions reported by large facilities and would result in only a very modest loss of reporting detail (and only for the smallest units) while increasing flexibility and reducing costs.

Response: EPA has made a number of significant adjustments in the final rule to the data reporting requirements of §98.36, both to clarify those requirements and to reduce the reporting burden. These adjustments are similar in effect to those suggested by the commenter.

For units that use Tiers 1, 2, and 3 to calculate CO_2 mass emissions, the cumulative 250 mmBtu/hr heat input capacity limit on the aggregation of units into a group has been dropped. Rather, the 250 mmBtu/hr restriction applies only to the individual units in the group. Therefore, for reporting purposes, individual units with maximum rated heat input capacities of 250 mmBtu/hr or less may be aggregated without limit into a single group, provided that the Tier 4 methodology is not required for any of the units, and all units in the group use the same Tier for any common fuel(s) that they combust. Units with maximum rated heat inputs greater than 250 mmBtu/hr using Tiers 1, 2, and 3 must report as individual units, unless they burn the same type of fuel provided by a common pipe or supply line; in that case, the owner or operator may opt to use the highest Tier required for a grouped unit for the calculation method with the common pipe reporting provisions in §98.36(c)(3). Units using Tier 4 must report as individual units unless they share a monitored common stack; in that case, the common stack reporting provisions of §98.36(c)(2) may be used.

Commenter Name: Keith Adams
Commenter Affiliation: Air Products and Chemicals, Inc.
Document Control Number: EPA-HQ-OAR-2008-0508-1142.1
Comment Excerpt Number: 29

Comment: The proposed rule requires reporting of GHG emissions for each type of fuel combusted. It is not clear if the expectation is discrete, or combined, reporting of the GHG emissions for each/all fuel types. Separate reporting of GHG emissions from the combustion of each discrete fuel type increases the risk that confidential business information (operating rates, fuel choices, operating efficiencies) could be revealed in reports accessible to domestic and international competitors and customers of the regulated source. Further, when CO_2 emissions are calculated using the Tier 4 method, there is no way to distinguish which CO_2 emissions come from each individual fuels. Air Products Comment: EPA should clarify that emission reporting is required only for the combined emissions from all fuels combusted. Reporting emissions for each fuel separately should not be required. Additionally, provisions to protect the confidentiality of all process, production and business- related information required under the rule should be strengthened. While Air Products accepts that facility-level emissions cannot be protected from public disclosure, it strongly requests all other information should, by default, be considered confidential business information and afforded the utmost protection from public disclosure.

Response: See the Preamble, Section II. R., and the response to comment EPA-HQ-OAR-2008-0508-1142.1 excerpt 28 for the response on CBI.

Units that calculate emissions using Tier 1, Tier 2, or Tier 3 must report emissions separately for each fuel type. However, §98.36(b)(7) of the final rule states that, for Tier 4 units, the annual CO_2 emissions will be reported for all fuels combined, and that any biogenic CO_2 emissions will also be reported separately. It also states that CH_4 and N_2O emissions are to be reported for each type of fuel combusted, calculated in accordance with §98.33(c). In §98.33(c)(3), EPA has specified that reporters using Tier 4 are to use the best available estimates of the annual heat input from each type of fuel combusted in the unit during the reporting year, excluding fuel used only for startup or ignition. This can be from CEMS data or engineering calculations. Using this data they are to calculate CH_4 and N_2O emissions for each fuel type.

In revising the final version of the rule, EPA has also added §98.36(d) to define data reporting requirements for units subject to Part 75, which requires total emissions by unit, not by fuel. EPA believes that these provisions in the final rule effectively address the concerns of the commenters.

Commenter Name: Leslie Bellas
Commenter Affiliation: National Lime Association (NLA)
Document Control Number: EPA-HQ-OAR-2008-0508-0520.1
Comment Excerpt Number: 19

Comment: 40 C.F.R. §98.36(b)(3) also requires sources to report the maximum rated heat input capacity of "process heaters." NLA requests EPA to confirm a statement made by EPA staff during a May 14 conference call that "process heaters" refers to all combustion equipment that has a nameplate capacity and is used to provide heat for the process.

Response: The commenter can find clear language in the final rule with regard to the definition of maximum rated heat input capacity in §98.6: "Maximum rated heat input capacity means the hourly heat input to a unit (in mmBtu/hr), when it combusts the maximum amount of fuel per hour that it is capable of combusting on a steady state basis, as of the initial installation of the unit, as specified by the manufacturer."

EPA uses the term "process heaters" to refer to a wide variety of devices in which heat is transferred indirectly to a process material. Nameplate capacity is not one of the necessary criteria for a combustion source to be included in this category.

Commenter Name: Keith Adams
Commenter Affiliation: Air Products and Chemicals, Inc.
Document Control Number: EPA-HQ-OAR-2008-0508-1142.1
Comment Excerpt Number: 31

Comment: The proposed rule describes in detail all the information required to be reported in order to verify the reported GHG emissions. The data compilation for all the information EPA seeks under §98.36(d) is extremely burdensome for regulated sources. While some of this information is used in order to develop, and assure the accuracy of, the emissions estimate, reporting all of this information is not necessary. In many cases, the necessity of this information is questionable, based on the rule's intention to develop an annual emissions estimate. Examples include §98.36(d)(1)(iv)(A) – number of operating hours per day of a particular emission source and §98.36(d)(1)(iv)(C) – daily CO_2 emissions (when an annual total is the rule's objective). Reporting at this level of detail also increases the risk that confidential business information could be revealed in reports accessible to domestic and international competitors and customers of the regulated source. Regulated sources should only be required to maintain the appropriate information that supports the emissions calculations and reporting basis, and make this information available upon request of EPA. Reporting of any information unrelated to emissions should not be required. All process, production and business-related information required to be reported under provisions to insure the veracity of the reported emissions should be afforded the maximum confidentiality protections.

Response: See the Preamble, Section II. R., and response to comment EPA-HQ-OAR-2008-0508-1142.1 excerpt 28 for the response on CBI.

EPA does not agree with the commenter's assertion that the amount of unit-level data and verification information to be reported electronically is excessive, burdensome or unnecessary. EPA has required the reporting of additional supporting data that are not directly used to calculate emissions but are nevertheless related to emissions and supportive of centralized verification efforts. For this mandatory GHG emissions reporting rule, two main approaches to data verification were considered, i.e., EPA verification and third-party verification. EPA decided on the former approach. In view of this, additional, unit-level information is deemed necessary to provide assurance that the reported facility-wide GHG emissions data are both credible and accurate. However, EPA has made a number of significant adjustments in the final rule to the data reporting requirements of §98.36, both to clarify those requirements and to reduce the reporting burden. EPA has also allowed facilities to keep more detailed QA records on-site, and submit them within 30 days of a written request from the Administrator or from the applicable state or local air pollution control agency (see §98.36(e)(3)).

EPA believes that it is appropriate to require submission of the total number of operating hours during the reporting year, and has retained this provision in the final rule. However, EPA has not finalized the requirements to report daily CO_2 emissions or the number of unit operating days. Sections 98.36(e)(2)(vi)(A) and (B) require facilities to report only the number of annual unit operating hours and the cumulative CO_2 mass emissions in each quarter of the reporting year. EPA believes that these revisions appropriately balance the need for quality assured GHG emission data with the need to reduce the burden on reporters.

Commenter Name: Leslie Bellas
Commenter Affiliation: National Lime Association (NLA)
Document Control Number: EPA-HQ-OAR-2008-0508-0520.1
Comment Excerpt Number: 16

Comment: 40 C.F.R. §98.36 requires unit or process-specific reporting of combustion emissions. The physical configuration of some lime plants precludes unit-specific emissions calculations because one fuel feed system may support multiple kilns. The Proposed Rulfe's objective to collect facility-level data is not undermined by permitting facility-wide reporting of combustion fuel emissions. As with lime process emissions, reporting combustion emissions by unit (kiln) does not improve the accuracy of the data. The Proposed Rule should follow the Western Climate Initiative's Final Draft of Essential Requirements of Mandatory Reporting, which permits facility-wide reporting of combustion fuel emissions. In accordance with 40 C.F.R. §98.37, a source can retain any unit-specific emissions information in company records and make it available to EPA for review. Facility-wide reporting of combustion emissions satisfies EPA's objective of developing facility-wide emissions information, without requiring businesses in highly competitive industries to disclose highly sensitive confidential business information.

Response: See the Preamble, Section II. R., for EPA's response on CBI.

EPA does not agree with the commenter's assertion that facility-wide information in itself satisfies EPA's objectives for the rule. Some potential programs under the Clean Air Act including NSPS, are applied at more disaggregated level than the overall facility. Because the main purpose of the rule is to collect information for climate policy development under the CAA, EPA views unit level reporting as appropriate. Additionally, to ensure high quality verified data, EPA has decided to serve the role as verifier rather than require third-party verification. In view of this, additional unit-level information is deemed necessary to provide assurance that the reported facility-wide GHG emissions data are both credible and accurate. The need for unit-level data is more pronounced for large units (i.e., greater than 250 mmBtu/hr) because of the overall share of emissions represented by these larger units at facilities, and the overall share of national emissions represented by these larger units collectively. However, as explained in the paragraphs below, EPA has made a number of significant adjustments in the final rule to the data reporting requirements of §98.36, both to clarify those requirements and to reduce the reporting burden.

For units that use Tiers 1, 2, and 3 to calculate CO_2 mass emissions, the cumulative 250 mmBtu/hr heat input capacity limit on the aggregation of units into a group has been dropped. Rather, the 250 mmBtu/hr restriction applies only to the individual units in the group. Therefore, for reporting purposes, individual units with maximum rated heat input capacities of 250 mmBtu/hr or less may be aggregated without limit into a single group, provided that the Tier 4 methodology is not required for any of the units, and all units in the group use the same Tier for any common fuel(s) that they combust. Units with maximum rated heat inputs greater than 250 mmBtu/hr using Tiers 1, 2, and 3 must report as individual units, unless they burn the same type of fuel provided by a common pipe or supply line; in that case, the owner or operator may opt to use the common pipe reporting provisions in §98.36(c)(3). This common pipe provision may be suitable for fuel lines that feed multiple lime kilns. Units using Tier 4 must report as individual units unless they share a monitored common stack; in that case, the common stack reporting provisions of §98.36(c)(2) may be used.

The supplementary verification information requirements of §98.36(e) have been clarified and, in some cases, differ substantively from the proposed rule. Paragraph (e)(1) in §98.36 clearly states that no additional verification information is required for sources that monitor and report emissions and heat input data using Part 75. This includes sources that elect to use the new §98.33(a)(5) alternative calculation methodologies for units not subject to the Acid Rain Program that report data to EPA according to Part 75. For sources using Tiers 1, 2, 3, and 4, the final rule streamlines some of the reporting. Sources using Tier 3 are required to report only monthly averages of the fuel carbon content and molecular weight rather than the proposed requirement to submit the results of each individual determination.

Commenter Name: Leslie Bellas
Commenter Affiliation: National Lime Association (NLA)
Document Control Number: EPA-HQ-OAR-2008-0508-0520.1
Comment Excerpt Number: 37

Comment: 40 C.F.R. §§98.36(d)(1)(iii) and (iv) require Tier 3 and Tier 4 facilities to report monthly data for the quantity of each type of fuel combusted per unit and the carbon content. Unit specific data may not be available because of the integrated nature of a lime plant and plant configuration. In addition, reporting fuel use data may allow competitors to more precisely determine the efficiency and capacity of kilns. 40 C.F.R. §98.36(d)(1)(iv) should be revised to require annual data for quantity of each type of fuel combusted at the facility. This is consistent with the Rule's intent to collect facility-level data and the Western Climate Initiative's reporting rule. Moreover, public reporting of this sensitive business information will not add substantive value to the annual report.

Response: See the Preamble, Section II. R., and the response to comment EPA-HQ-OAR-2008-0508-0520.1 excerpt 16 for EPA's response on CBI. Also see the response to the same comment, comment EPA-HQ-OAR-2008-0508-0520.1, excerpt 16 for the response on the need for unit-level data, and additional flexibility EPA has provided for reporting, such as aggregation and common pipe configurations at facilities that may be suitable for lime plants.

Commenter Name: Leslie Bellas
Commenter Affiliation: National Lime Association (NLA)
Document Control Number: EPA-HQ-OAR-2008-0508-0520.1
Comment Excerpt Number: 38

Comment: 40 C.F.R. §98.36(d)(1)(iv) requires Tier 4 facilities to report daily CO_2 emission rates from CEMS and the hours of operation and operating days. 40 C.F.R. §98.36(d)(1)(iv)(A) should be revised to delete the requirement to report operating days and operating hours. Given the intent of the Rule, which is to report GHG emissions, there is little value in requiring source to report operating days or hours. The requirement to report daily CO_2 emission rates (40 C.F.R. §98.36(d)(1)(iv)(C)) for Tier 4 should be deleted. EPA is requiring electronic reporting, so this level of detailed reporting will require sources to enter a significant amount of data. Hourly CO_2 emission rates as generated by the CEMS can be retained in company records and made available for review in accordance with 40 C.F.R. §98.37. Public disclosure of this information does not further the objectives of the Proposed Rule.

Response: EPA believes that it is appropriate to require submission of the total number of operating hours during the reporting year, and has retained this provision in the final rule. However, EPA has not finalized the requirements to report daily CO_2 emissions or the number of unit operating days. Sections 98.36(e)(2)(vi)(A) and (B) require facilities to report only the

number of annual unit operating hours and the cumulative CO_2 mass emissions in each quarter of the reporting year. EPA believes that these revisions appropriately balance the need for quality assured GHG emission data with the need to reduce the burden on reporters.
See the Preamble, Section II. R., and the response to comment EPA-HQ-OAR-2008-0508-0520.1 excerpt 16 for EPA's response on CBI.

Commenter Name: Lorraine Krupa Gershman
Commenter Affiliation: American Chemistry Council (ACC)
Document Control Number: EPA-HQ-OAR-2008-0508-0423.2
Comment Excerpt Number: 68

Comment: In §98.36(b) and (c), EPA should modify these sections to allow a facility to report only the total CO_2 for a facility instead of unit-specific calculation and reporting. This is advantageous to EPA as an inventory calculation tool because it will capture smaller sources and make the total inventory more complete. Many facilities do not have the meters required to do unit-by-unit calculations. Such calculations would be burdensome and excessive and would not add to the overall use of the information to develop a greenhouse gas inventory. Examples illustrating this concern include: (1) Natural gas is only metered where it enters the site. Therefore, EPA should allow calculation and reporting of site wide CO_2e. Although combustion unit specific emissions would not be reported, the inventory of CO_2 emissions from natural gas combustion at the site would be more complete and thorough than as currently proposed in Subpart C. (2) The only record of fuel oil usage may be the amount delivered to the site. Some fuel oil is used in emergency engines. Since emergency engine use cannot be readily separated from the total consumption, the inventory of CO_2 emissions from fuel oil combustion at the site would be more complete and thorough than as currently proposed in Subpart C.

Response: Regarding the situation where natural gas is only metered "at the gate," the common pipe or unit aggregation options in §98.36(c) could be used to substantially reduce the reporting burden. Regarding the issue of quantifying fuel usage by emergency generators (which are exempt from GHG emissions reporting), this only becomes an issue when the generators are fed from a common fuel pipe or supply tank that also serves affected units. EPA has included a definition of "company records" in §98.6 that applies to Tiers 1 and 2. The definition (see below) provides a great deal of flexibility in determining fuel usage.

"Company records" means a complete record of the methods used, the measurements made, and the calculations performed to quantify fuel usage. Company records may include, but are not limited to, direct measurements of fuel consumption by gravimetric or volumetric means, tank drop measurements, and calculated values of fuel usage obtained by measuring auxiliary parameters such as steam generation or unit operating hours. Fuel billing records obtained from the fuel supplier qualify as company records."

Thus, where a group of units that includes emergency generators is fed by a common supply line, a best available estimate of the fuel used by the emergency generators can be made using "company records," and then the result can be subtracted out from the total amount of fuel consumed by the group, prior to calculating the GHG emissions for the affected units.

See the Preamble, Section II. R., and the response to comment EPA-HQ-OAR-2008-0508-0520.1 excerpt 16 for EPA's response on CBI. Also, see the response to the same comment, comment EPA-HQ-OAR-2008-0508-0520.1, excerpt 16 for the response to the need for unit-level data, including additional flexibility EPA has provided for aggregation and common pipe configurations at facilities.

Commenter Name: Lorraine Krupa Gershman
Commenter Affiliation: American Chemistry Council (ACC)
Document Control Number: EPA-HQ-OAR-2008-0508-0423.2
Comment Excerpt Number: 69

Comment: For §98.36(b) and (c), there are situations when the fuel-type might be CBI. In these instances, facilities will not want to report their fuel type, and EPA should not require it to be reported. This is especially true for §98.36(b)(5) for hydrogen production. As an alternate to requiring each individual fuel type to be reported, ACC recommends limiting the reporting to the following categories: liquid, other solid fuels, MSW, biomass, natural gas, and other gaseous fuels [see Table C-1 in Preamble].

Response: See the Preamble, Section II. R., and response to comment EPA-HQ-OAR-2008-0508-0520.1 excerpt 16 for EPA's response on CBI. Reporting of fuel type is critical for verification of emissions estimates.

Commenter Name: Lorraine Krupa Gershman
Commenter Affiliation: American Chemistry Council (ACC)
Document Control Number: EPA-HQ-OAR-2008-0508-0423.2
Comment Excerpt Number: 70

Comment: In §98.36(c), ACC supports all of the alternative calculation methods allowing unit aggregation that EPA has provided. In §98.36(c)(3), there are certain situations where using the common pipe method will severely overstate the greenhouse gas emissions such as when natural gas is used as a feedstock for manufacturing processes instead of as a fuel. In these cases, EPA should allow the use of engineering calculations in lieu of measured flow rates within the common pipe method.

Response: EPA acknowledges the commenter's concerns, and has addressed this issue in the final rule. Section 98.36(c)(3) states: If a portion of the fuel measured at the common pipe is diverted to a chemical or industrial process where it is used but not combusted, provided that the amount of fuel diverted is also measured with a calibrated flow meter, you may subtract out the diverted fuel from the fuel measured at the common pipe prior to performing the GHG emissions calculations."

Commenter Name: Lorraine Krupa Gershman
Commenter Affiliation: American Chemistry Council (ACC)
Document Control Number: EPA-HQ-OAR-2008-0508-0423.2
Comment Excerpt Number: 71

Comment: The Acid Rain regulation does not require reporting CO_2 by fuel if a CEMS is present, and this rule should not require CO_2 by fuels in any part of §98.36.

Response: EPA acknowledges the commenter's concerns, and has addressed this issue in the final rule. Units calculating emissions using Tiers 1, 2, or 3 must report emissions by fuel type. However, §98.36(b)(7) of the final rule states that, for Tier 4 units, the annual CO_2 emissions will be reported for all fuels combined, and that any biogenic CO_2 emissions will also be reported separately. It also states that CH_4 and N_2O emissions are to be reported for each type of fuel combusted, calculated in accordance with §98.33(c). In §98.33(c)(3), EPA has specified that reporters using Tier 4 are to use the best available estimates of the annual heat input from each type of fuel combusted in the unit during the reporting year, excluding fuel used only for startup or ignition. This can be from CEMS data or engineering calculations. Using this data they are to calculate CH_4 and N_2O emissions for each fuel type.

In revising the final version of the rule, EPA has also added §98.36(d) to define data reporting requirements for units subject to Part 75, which requires total emissions by unit, not by fuel. EPA believes that these provisions in the final rule effectively address the concerns of the commenters.

Commenter Name: Lorraine Krupa Gershman
Commenter Affiliation: American Chemistry Council (ACC)
Document Control Number: EPA-HQ-OAR-2008-0508-0423.2
Comment Excerpt Number: 72

Comment: In §98.36, EPA does not appear to have limited the reporting by fuel type, even with CEMS being used. However, EPA must do so by changing the rule to allow aggregating fuel types at least when CEMS are used, because CEMS do not allow separating CO_2 emissions by fuel type if different fuels are burned at the same time. An example would be process gas fuel that is supplemented with natural gas.

Response: EPA acknowledges the commenter's concerns, and has addressed this issue in the final rule. Section 98.36(b)(7) of the final rule states that, for Tier 4 units, the annual CO_2 emissions will be reported for all fuels combined, and that any biogenic CO_2 emissions will also be reported separately. It also states that CH_4 and N_2O emissions are to be reported for each type of fuel combusted, calculated in accordance with §98.33(c). In §98.33(c)(3), EPA has specified that reporters using Tier 4 are to use the best available estimates of the annual heat input from each type of fuel combusted in the unit during the reporting year, excluding fuel used only for startup or ignition. This can be from CEMS data or engineering calculations. Using this data they are to calculate CH_4 and N_2O emissions for each fuel type.
In revising the final version of the rule, EPA has also added §98.36(d) to define data reporting requirements for units subject to Part 75, which requires total emissions by unit, not by fuel.

EPA believes that these provisions in the final rule effectively address the concerns of the commenters.

Commenter Name: Randal G. Oswald
Commenter Affiliation: Integrys Energy Group, Inc.
Document Control Number: EPA-HQ-OAR-2008-0508-0569.1
Comment Excerpt Number: 4

Comment: Subpart C, unit level reporting requirement in 98.36(b)(5) is inconsistent with Tier 4 and 40 CFR Part 75 monitoring methods. This section requires that annual GHG emissions are reported for each fuel type, but Tier 4 and Part 75 monitoring methods do not monitor and report emissions by each fuel type. Section 98.36(b)(5) reads, "The calculated CO_2, CH_4, and N_2O emissions for each type of fuel combusted, expressed in metric tons of each gas and in metric tons of CO_2e". Tier 4 and 40 CFR Part 75 monitoring methods calculate CO_2 mass emissions and heat input from all fuels combusted in a unit. The proposed rule should clarify that Tier 4 and 40 CFR Part 75 emissions are not required to report GHG emissions by type of fuel.

Response: EPA acknowledges the commenter's concerns, and has addressed this issue in the final rule. Section 98.36(b)(7) of the final rule states that, for Tier 4 units, the annual CO_2 emissions will be reported for all fuels combined, and that any biogenic CO_2 emissions will also be reported separately. It also states that CH_4 and N_2O emissions are to be reported for each type of fuel combusted, calculated in accordance with §98.33(c). In §98.33(c)(3), EPA has specified that reporters using Tier 4 are to use the best available estimates of the annual heat input from each type of fuel combusted in the unit during the reporting year, excluding fuel used only for startup or ignition. This can be from CEMS data or engineering calculations. Using this data they are to calculate CH_4 and N_2O emissions for each fuel type.

In revising the final version of the rule, EPA has also added §98.36(d) to define data reporting requirements for units subject to Part 75, which requires total emissions by unit, not by fuel. EPA believes that these provisions in the final rule effectively address the concerns of the commenters.

Commenter Name: Keith Adams
Commenter Affiliation: Air Products and Chemicals, Inc.
Document Control Number: EPA-HQ-OAR-2008-0508-1142.1
Comment Excerpt Number: 30

Comment: The proposed rule offers the option to calculate and report emissions for aggregated units under the provisions of §98.36(c)(1), (2), and (3). These are effective methods by which a source can streamline the process measurement, emission calculation, and emission reporting requirements. Air Products strongly support the optional aggregation provisions and encourages EPA to consider expanding the applicability of such options. For example, eliminating the restriction of the aggregated maximum capacity of 250 mm BTU/hr under §98.36(c)(1) would not compromise the accuracy or completeness of the reported data, but could reduce the emission calculation and reporting burden and provide some additional protection to confidential business information.

Response: See the Preamble, Section II. R., and the response to comment EPA-HQ-OAR-2008-0508-0520.1 excerpt 16 for EPA's response on CBI.

EPA has made a number of significant adjustments in the final rule to the data reporting requirements of §98.36, both to clarify those requirements and to reduce the reporting burden.

For units that use Tiers 1, 2, and 3 to calculate CO_2 mass emissions, the cumulative 250 mmBtu/hr heat input capacity limit on the aggregation of units into a group has been dropped. Rather, the 250 mmBtu/hr restriction applies only to the individual units in the group. Therefore, for reporting purposes, individual units with maximum rated heat input capacities of 250 mmBtu/hr or less may be aggregated without limit into a single group, provided that the Tier 4 methodology is not required for any of the units, and all units in the group use the same Tier for any common fuel(s) that they combust. Units with maximum rated heat inputs greater than 250 mmBtu/hr using Tiers 1, 2, and 3 must report as individual units, unless they burn the same type of fuel provided by a common pipe or supply line; in that case, the owner or operator may opt to use the highest Tier required for a grouped unit for the calculation method with the common pipe reporting provisions in §98.36(c)(3). Units using Tier 4 must report as individual units unless they share a monitored common stack; in that case, the common stack reporting provisions of §98.36(c)(2) may be used.

Commenter Name: Michael DiMauro
Commenter Affiliation: Massachusetts Municipal Wholesale Electric Company (MMWEC)
Document Control Number: EPA-HQ-OAR-2008-0508-0580
Comment Excerpt Number: 6

Comment: Fuel Data Applicable to a Group of Units: The Proposed Rule does not appear to discuss the reporting of fuel consumption measurement data that represents the combined usage for a group of stationary combustion units. Often, records documenting fuel usage (aside from fuel metering data) are not available at, or applicable to, the individual unit level. Examples of records that provide accurate information on fuel consumption, but which do not represent unit level measurements include: (a) Oil Tank Drop measurements, for storage tanks at facilities operating multiple oil fired units; (b) documentation of fuel oil deliveries to a site that operates multiple combustion units which are served by one or more non-dedicated oil tanks; and (c) documentation of natural gas usage on billing invoices where multiple (non-dedicated) gas lines serve the facility and the facility operates multiple combustion units. These monitoring situations are analogous to a common pipe fuel configuration in that fuel usage is measured at a location from which fuel is delivered to several combustion sources. For common pipes, GHG emission reporting is only required at the aggregate level, not for the individual combustion units (see 98.36(c)(3)). However, this type of monitoring also has some aspects in common with aggregation (as does common pipe monitoring), but "aggregation" is only allowed for a group of units whose total design heat input is < 250 MMBtu/hr, which is a very restrictive condition. For facilities at which a fuel is measured at a common supply point serving multiple units (e.g. an oil storage tank), and but which is not a common pipe, the rule should provide clarification and elaboration on the following issues: a) Whether fuel consumption should be only reported at the group level, for the set of combustion units to which this fuel usage documentation is applicable (as with common pipes), or if fuel usage must be apportioned to the individual unit level; b) The rule should also address the situation in which some of the combustion units in the group are subject to the Acid Rain or CAIR Programs, and are therefore individually metered. In this situation, the rule should allow fuel usage from such Part 75 units to be extracted from the group fuel usage totals (i.e. Group Fuel Consumption for Non-Part 75 Units = Total Fuel Consumption for entire group from documented records – Directly Monitored Fuel Consumption for Part 75 Units) c) If apportionment is required, the rule should provide guidance on acceptable types of apportionment schemes. Part 75 contains several apportionment approaches that could be adopted, including apportionment based on Unit level MW output, Unit level steam production or Unit level fuel flows measured by uncertified meters. d) It should be clarified that this monitoring approach is not considered aggregation and therefore is not subject to the restriction that the combined design heat input of the group be < 250 MMBtu/hr

Response: EPA acknowledges the concerns of the commenter, and has revised the reporting alternatives described in §98.36(c) to reduce the burden on reporters. First, for units that use Tiers 1, 2, and 3 to calculate CO_2 mass emissions, the cumulative 250 mmBtu/hr heat input capacity limit on the aggregation of units into a group has been dropped. Rather, the 250 mmBtu/hr restriction applies only to the individual units in the group. Therefore, for reporting purposes, individual units with maximum rated heat input capacities of 250 mmBtu/hr or less may be aggregated without limit into a single group, provided that the Tier 4 methodology is not required for any of the units, and all units in the group use the same Tier for any common fuel(s) that they combust. Furthermore, EPA has clarified the provisions for common pipe reporting in §98.36(c)(3). To use common-pipe reporting, a facility must determine the total amount of fuel combusted by the common pipe units using a calibrated fuel flow meter. EPA has added a provision allowing facilities to subtract fuel diverted away from these units prior to performing GHG emissions calculations, provided that the amount of fuel diverted is measured with a calibrated fuel flow meter. EPA believes that these revisions will reduce the burden of reporting.

The commenter suggests that combustion units subject to the Acid Rain or CAIR Programs that are part of a group of units which includes non-Part 75 units should be allowed to determine fuel consumption for the non-Part 75 units using a subtractive method. EPA assumes that the commenter is referring to a common pipe situation where a supply line serves both Part 75 units and non-Part 75 units. If the non-Part 75 units are eligible for the Tier 1 or 2 methodology, "company records" (as defined in 98.6) may be used to determine the total fuel consumption for the group of units. If Tier 3 is required, a calibrated fuel flow meter must be used at the common pipe to measure the total amount of fuel combusted.

The final rule requires GHG emissions from Part 75 units to be reported separately, under the same unit, stack or pipe ID numbers that are used for Part 75 electronic reporting. Therefore, if Part 75 units share a common supply line with non-Part 75 units, it is appropriate to subtract out the individually metered fuel combusted by the Part 75 units from the total fuel combusted by the group before calculating the CO_2 emissions for the group of non-Part 75 units.

Commenter Name: Michael E. Van Brunt
Commenter Affiliation: Covanta Energy Corporation
Document Control Number: EPA-HQ-OAR-2008-0508-0548.1
Comment Excerpt Number: 5

Comment: Consistent with international precedent, the Proposed Rule requires that biogenic emissions be reported separately; however, it appears that these biogenic emissions are included in the total reported CO_2 emissions. To be fully consistent with international precedents, the EPA must clarify that biogenic emissions of CO_2 are not to be included in total CO_2 emissions. According to the IPCC 2006 guidelines, "the CO_2 emissions from combustion of biomass materials (e.g. paper, food, and wood waste) contained in the waste are biogenic emissions and should not be included in national total emission estimates."

Response: While EPA has decided to track biogenic emissions separately, they still must be reported. EPA believes that it is clear in §98.2(b)(1)(i) that CO_2 emissions from biogenic fuels do not count toward the 25,000 metric ton threshold for reporting for stationary combustion units, although CH_4 and N_2O emissions from biogenic fuels must be considered. Furthermore, EPA notes that the tracking of carbon of biogenic nature is accounted, for national GHG inventories, within the Land Use, Land-Use Change and Forestry sector by examining the carbon fluxes of forestry. This means that the exhalation of carbon and uptake of carbon by trees is examined together. All net emissions are included in national totals. Additionally, EPA plans to make the distinction between biogenic and non-biogenic CO_2 emission clear in any document or database available to the public.

Commenter Name: Kathleen M. Sgamma
Commenter Affiliation: Independent Petroleum Association of Mountain States (IPAMS)
Document Control Number: EPA-HQ-OAR-2008-0508-0521.1
Comment Excerpt Number: 13

Comment: IPAMS supports the aggregated reporting of units with combined maximum rated heat input of 250 MMBtu/hr or less.

Response: EPA appreciates this comment, and believes that the final rule includes further clarification and flexibility regarding aggregation provisions. For units that use Tiers 1, 2, and 3 to calculate CO_2 mass emissions, the cumulative 250 mmBtu/hr heat input capacity limit on the aggregation of units into a group has been dropped. Rather, the 250 mmBtu/hr restriction applies only to the individual units in the group. Therefore, for reporting purposes, individual units with maximum rated heat input capacities of 250 mmBtu/hr or less may be aggregated without limit into a single group, provided that the Tier 4 methodology is not required for any of the units, and all units in the group use the same Tier for any common fuel(s) that they combust.

Commenter Name: Angus E. Crane
Commenter Affiliation: North American Insulation Manufacturers Association (NAIMA)
Document Control Number: EPA-HQ-OAR-2008-0508-0537.1
Comment Excerpt Number: 13

Comment: The proposed rule should provide a longer, reasonable period of time to respond to EPA's written requests. Proposed section 98.36 sets forth data reporting requirements. Within this section, proposed section 98.36(d)(2) states that "[w]ithin 7 days of receipt of a written request (e.g., a request by electronic mail) from the Administrator or from the applicable air pollution control agency, the owner or operator shall submit the explanations described in Section 98.34(a) and (b)" in a certain manner. Seven days is an unreasonably short period of time to respond to such requests. On some occasions, EPA and other regulatory agencies have submitted requests for information to owner/operators during periods when the people necessary to assemble the response are unavailable, e.g., holidays such as Christmas and Thanksgiving. Moreover, there is no reason for requiring such a quick response. GHG emissions, and any questions about them, pose no immediate health or environmental risk that will be worsened during the 23 days needed to extend the proposed reporting deadline to a more reasonable 30-day period. Accordingly, NAIMA asks that EPA revise the proposed rule to provide a 30-day, not a 7-day, response time under proposed section 98.36(d)(2).

Response: EPA acknowledges the commenter's concerns. In §98.36(e)(3) of the final rule, EPA has allowed owners or operators 30 days from receipt of a written request for information to respond to that request.

Commenter Name: D. Lawrence Zink
Commenter Affiliation: Montana Sulphur & Chemical Company Inc. (MSCC)
Document Control Number: EPA-HQ-OAR-2008-0508-0505.1
Comment Excerpt Number: 14

Comment: At our facility, and we believe at many others, it is fruitless and possibly infeasible to allocate fuel usage to individual units on a "best available data" basis because we have a single fuel gas header that supplies combustion fuel to several and varying process heaters, incinerators, and boilers. None of these individual heaters etc., actually approaches the 30,000,000 BTU/hr or 25,000 ton thresholds individually, and it may be that in aggregate they also do not meet these thresholds. The fuel is frequently a mixture of natural gas and refinery fuel gas, with the ratio of gases varying over a day. Our records are limited to the total of each type of fuel gas supplied over a day. We may have estimates of the ratio of the total fuel gas used in various units; even so, we believe it is unnecessarily complex to require reporting of emissions by fuel type from each individual unit inside a facility, let alone to invoke "best available" and/or "all available" data considerations/decisions on potentially thousands of events during a year. Ultimately the volume of CO_2e emissions from fuel burning is what it is and is determined by the total amount of fuel burned at the facility. It is not relevant to precisely identify which process heater or boiler accounted for which molecule of CO_2. Furthermore, most of these emissions are merged to a single emission point where they mix with process emissions from other than fuel burning activities. We suggest that for fuel burning emissions from a site location, aggregate fuel data should be more than sufficient, for example, if the emissions are all co-located on the same site, or are emitted within (for instance) one kilometer of each other. It may not be unreasonable to ask sources to identify the contributing units by name or label, but it serves no purpose to force an allocation, let alone one based on "all process data" or "best available" criteria. None of this internal information, even if derived from the best possible measurements, has any bearing on purported impacts from GHG emissions.

Response: See the response to comment EPA-HQ-OAR-2008-0508-1142.1 excerpt 31 for the response on the level of reporting, and the response to comment EPA-HQ-OAR-2008-0508-0520.1 excerpt 16 for the response indicating the additional flexibility provided to reporters, particularly for common pipe and aggregated unit circumstances.

For the situation described by the commenter (i.e., a supply line that feeds a single type of fuel to multiple units), the common pipe reporting option in §98.36(c)(3) is the best option for quantifying CO_2 emissions and to reduce the reporting burden. If the gas combusted by the units is listed in Table C-1, then Tier 1 or Tier 2 could be used to calculate CO_2 emissions, with company records used to quantify fuel consumption. If the gas is not listed in Table C-1, then, in this case, since none of the individual units served by the supply line is > 250 mmBtu/hr, GHG emissions reporting is not required.

EPA further notes that the alternative reporting requirements, such as for the aggregation of units or the use of common pipes, are allowed to be used by multiple groupings of units at a facility. For example, if a facility has a single gas header for supplying natural gas to multiple units, it may use the common pipe reporting option and report a single GHG value. In addition, a facility may aggregate multiple small units (i.e., 250 mmBtu/hr) that combust another common fuel and report a single GHG value. The use of the alternative reporting requirements is allowed for multiple groupings of units, so the comment about determining ratios of fuel use by units is not necessary if the reporter chooses the reporting alternatives.

Commenter Name: See Table 4
Commenter Affiliation:
Document Control Number: EPA-HQ-OAR-2008-0508-0455.1
Comment Excerpt Number: 16

Comment: Proposed §98.36(b)(5) states that reporting is required for "[t]he calculated CO_2, CH_4, and N_2O emissions for each type of fuel combusted, expressed in metric tons of each gas and in metric tons of CO_2e" (emphasis added). However, Tier Four of Subpart C of the Proposal and 40 C.F.R. Part 75 calculation methods determine CO_2 mass emissions and heat input by combining all fuel types combusted in a unit. Therefore, when using the Tier Four calculation methods, it is impossible to report the calculated CO_2 mass emissions by each type of fuel. EPA should clarify that those facilities using Tier Four and 40 C.F.R. Part 75 calculations are not required to report GHG emissions by fuel type.

Response: EPA acknowledges the commenter's concerns, and has addressed this issue in the final rule. Section 98.36(b)(7) of the final rule states that, for Tier 4 units, the annual CO_2 emissions will be reported for all fuels combined, and that any biogenic CO_2 emissions will also be reported separately. It also states that CH_4 and N_2O emissions are to be reported for each type of fuel combusted, calculated in accordance with §98.33(c). In §98.33(c)(3), EPA has specified that reporters using Tier 4 are to use the best available estimates of the annual heat input from each type of fuel combusted in the unit during the reporting year, excluding fuel used only for startup or ignition. This can be from CEMS data or engineering calculations. Using this data they are to calculate CH_4 and N_2O emissions for each fuel type.

In revising the final version of the rule, EPA has also added §98.36(d) to define data reporting requirements for units subject to Part 75, which requires total emissions by unit, not by fuel. EPA believes that these provisions in the final rule effectively address the concerns of the commenters.

Commenter Name: Steven D. Meyers
Commenter Affiliation: General Electric Company (GE)
Document Control Number: EPA-HQ-OAR-2008-0508-0532.1
Comment Excerpt Number: 19

Comment: Paragraph (c) of Section 98.36 of the proposed regulations provides that small fuel combustion sources may be aggregated for reporting as long as the aggregate maximum rated heat input capacity of the units does not exceed 250 MMBtu/hr. In addition, this paragraph also allows the aggregated reporting of oil-fired or gas-fired fuel combustion units as long as the fuel combustion units are fed through a common fuel supply line. These provisions will be very important to lessen the reporting burden of many industrial emission sources such as GE facilities that may have numerous boilers, process heaters, process flames, furnaces, dryers, space heaters and other fuel combustion sources. In some cases, an industrial facility may have numerous gas-fired units that are fired by a common gas line that is metered only at the fence line. Significant expense would be incurred both for the installation of numerous gas meters and for the data collection and emission calculation activities that would be needed to report these units individually.

Response: EPA appreciates the commenter's support, and has made a number of significant adjustments in the final rule to the data reporting requirements of §98.36, both to clarify those requirements and to reduce the reporting burden.

For units that use Tiers 1, 2, and 3 to calculate CO_2 mass emissions, the cumulative 250 mmBtu/hr heat input capacity limit on the aggregation of units into a group has been dropped. Rather, the 250 mmBtu/hr restriction applies only to the individual units in the group. Therefore, for reporting purposes, individual units with maximum rated heat input capacities of 250 mmBtu/hr or less may be aggregated without limit into a single group, provided that the Tier 4 methodology is not required for any of the units, and all units in the group use the same Tier for any common fuel(s) that they combust. Units with maximum rated heat inputs greater than 250 mmBtu/hr using Tiers 1, 2, and 3 must report as individual units, unless they burn the same type of fuel provided by a common pipe or supply line; in that case, the owner or operator may opt to use the highest Tier required for a grouped unit for the calculation method with the common pipe reporting provisions in §98.36(c)(3). Units using Tier 4 must report as individual units unless they share a monitored common stack; in that case, the common stack reporting provisions of §98.36(c)(2) may be used.

Commenter Name: See Table 7
Commenter Affiliation:
Document Control Number: EPA-HQ-OAR-2008-0508-0412.1
Comment Excerpt Number: 23

Comment: GPA also supports the aggregated reporting of units with combined maximum rated heat input of 250 MMBtu/hr or less.

Response: EPA appreciates this comment, and believes that the final rule includes further clarification and flexibility regarding aggregation provisions that will reduce the burden on sources. For units that use Tiers 1, 2, and 3 to calculate CO_2 mass emissions, the cumulative 250 mmBtu/hr heat input capacity limit on the aggregation of units into a group has been dropped. Rather, the 250 mmBtu/hr restriction applies only to the individual units in the group. Therefore, for reporting purposes, individual units with maximum rated heat input capacities of 250 mmBtu/hr or less may be aggregated without limit into a single group, provided that the Tier 4 methodology is not required for any of the units, and all units in the group use the same Tier for any common fuel(s) that they combust.

Commenter Name: Linda Farrington
Commenter Affiliation: Eli Lilly and Company (Lilly)
Document Control Number: EPA-HQ-OAR-2008-0508-0680.1
Comment Excerpt Number: 20

Comment: The proposed language in Subpart C requires facilities to report GHG emissions separately for each type of fuel used in each combustion unit. Lilly believes this level of detail is unnecessary and we question the value gained from having to report emission data for individual units. Because the amount of GHG emissions varies among different types of fuels, we understand the need to report emission by fuel type. But we disagree with the requirement to report GHG emissions for each individual combustion unit. The reporting alternatives for the aggregation of small units and the monitored common stack configurations found in §98.36 provide some relief, but further simplification could be achieved by allowing facilities to use Tier 1 or Tier 2 equations to calculate GHG emissions for each type of fuel used at the facility (instead of calculating emissions for each individual combustion unit). For example, a facility may have a single fuel oil storage tank that supplies fuel to multiple boilers and generators. Because the proposed rule requires reporting by combustion unit, the facility would be required to estimate fuel usage for each individual boiler and generator. If the proposed rule were simplified to require reporting at a facility level only, the reporter would only need to monitor the level in the fuel oil storage tank and perform the emission calculations based upon the total fuel used at the facility. This would simplify the site's procedures, reduce the amount of required monitoring, and decrease the volume of individual data points that must be reported and verified by the EPA.

Response: See the response to comment EPA-HQ-OAR-2008-0508-0520.1 excerpt 16 for EPA's response to the need for unit-level data, including additional flexibility EPA has provided for unit aggregation and common pipe configurations at facilities. Unit-level data on fuel consumption by type is a critical component of a rigorous and credible verification program.

Commenter Name: Traylor Champion
Commenter Affiliation: Georgia-Pacific, LLC (GP)
Document Control Number: EPA-HQ-OAR-2008-0508-0380.1
Comment Excerpt Number: 27

Comment: EPA should clarify the common pipe language to specifically allow its use for combination boilers that combust more than one fuel. Notwithstanding our preferred approach of using the Tier 1 methodology on fuels coming across the fenceline rather than at the unit level regardless of the size of the combustion unit, the common pipe aggregation should be allowed for combination units that combust more than one fuel and this should be clearly stated in the rule language. EPA should add language that clarifies this intent by inserting a second sentence in §98.36(c)(3) that reads: "This reporting option can be used even if one or more of the units combusting the aggregated fuel burns a separate fuel." Also, the language in the reporting elements in subsections (iv), (vi), (vii), and (viii) should be updated to be consistent with the above inserted language.

Response: If the common pipe option is selected, the rule requires that all of the units served by the pipe combust the same type of fuel. Therefore, a unit that combusts both fuel from a common supply line and one or more additional fuels cannot use the common pipe reporting option. It must report as an individual unit or possibly as part of a group of aggregated units under §98.36(c)(1), if it is small (≤ 250 mmBtu/hr) and there are other small combustion units at the facility. The unit aggregation option may be used only if Tier 4 is not required for any of the units in the group, and if the same Tier is used for any fuel(s) that the units have in common.

Commenter Name: Lorraine Krupa Gershman
Commenter Affiliation: American Chemistry Council (ACC)
Document Control Number: EPA-HQ-OAR-2008-0508-0423.2
Comment Excerpt Number: 75

Comment: There is a reference to equation C-14 in both §98.3 6(d)(1)(vii)(D) and (E). We believe that reference is incorrect. The correct reference should be to equation C-13.

Response: EPA has corrected this error in the final rule.

Commenter Name: William Fred Durham
Commenter Affiliation: West Virginia Department of Environmental Protection (DEP)
Document Control Number: EPA-HQ-OAR-2008-0508-0629.1
Comment Excerpt Number: 7

Comment: Paragraph (a) of 98.36 Data reporting requirements of the proposed MRR states "In addition to the facility-level information required under 98.3, the annual GHG emissions report shall contain the unit-level or process-level emissions data in paragraph (b) and (c) of this section (as applicable) and the emissions verification data in paragraph (d) of this section." The Preamble, Fact Sheet, Frequently Asked Questions, and PowerPoint downloaded from the

Resources part of EPA's MRR webpage at http://www.epa.gov/climatechange/emissions/ ghgrulemaking.html indicate that facility-level reporting is required, which implies that unit- or process-level reporting is not required. The facility-level reporting appears to be intended to contrast with corporate-level reporting typical of voluntary GHG programs. On the other hand, 98.36 seems to state clearly that all facilities subject to the MRR must report at the unit- or process-levels. The verbiage contained in 98.36 may appear clear to those who work with the Federal Register on a daily basis but it is less so to those who do not. The DAQ requests EPA to expand 98.36 to expressly state which types of facilities must report at the unit- or process-levels and to clarify the discussion in its Fact Sheets, etc. to make clear the distinction between its corporate to facility level reporting and its facility to unit- or process-level reporting requirements.

Response: See the Preamble, Section II. F., for the responses on the selection of the level of reporting, as well as the general content of the annual emissions report. EPA intends to make available guidance materials that to assist stakeholders in understanding the various general and source category-specific provisions of the rule.

The unit-level reporting provisions in §98.36 are intended to supplement the facility-level report, and apply only to those units for which reporting under Subpart C, General Stationary Combustion is required.

Commenter Name: Michael A. Palazzolo
Commenter Affiliation: Alcoa, Inc.
Document Control Number: EPA-HQ-OAR-2008-0508-0650.1
Comment Excerpt Number: 9

Comment: The proposed rule requires the owner/operator to have a written Quality Assurance Performance Plan (QAPP). This plan must have a detailed description of the procedures used for maintenance and repair of flow meters and "a maintenance log shall be kept". This requirement for a QAPP is not workable for the many owners and operators who plan to determine their GHG emissions based on utility fuel bills or invoices. For example, natural gas supply meters are frequently owned or operated by the utility, and the facility purchasing the natural gas cannot control or specify the maintenance, repair or recordkeeping for these meters. To resolve this issue, we recommend that EPA not require a QAPP for situations where a fuel flow meter or other measurement device is owned/operated by the fuel supplier rather than the facility owner/operator. The accuracy required for commercial sale of the fuel will be sufficient to meet the GHG reporting needs.

Response: See the Preamble, Section II. M., and separate comment response document volume for the response on the general recordkeeping requirements.

The requirement for a QAPP has been replaced by a facility Monitoring Plan under §98.3. The Monitoring Plan does not require a description of the supplier's QA procedures but should indicate which pieces of data are provided by the suppliers. The commenter should note that EPA has revised Subpart C to clarify that facilities are not responsible for the calibration and on-going QA of fuel billing meters provided that the fuel supplier and the unit(s) combusting the fuel do not have any common owners and are not owned by subsidiaries or affiliates of the same company.

Commenter Name: Vince Brisini
Commenter Affiliation: RRI Energy Inc. (RRI)
Document Control Number: EPA-HQ-OAR-2008-0508-0618.1
Comment Excerpt Number: 10

Comment: U.S. EPA should clarify in its GHG reporting rule that facilities currently reporting under Part 75 and applying Tier 4 methodology to those affected EGUs — are not required to report GHG emissions by fuel type. In §98.36(b)(5), U.S. EPA proposes to require reporters to calculate GHG emissions by each type of fuel combusted; however, the Tier 4 methodology described in the proposed GHG reporting rule, like calculation methods described in Part 75, specify that CO_2 mass emissions and heat input are calculated by combining all fuel types combusted in a unit. Therefore, it is unnecessary and burdensome for reporters using Tier 4 calculation methods as required by Part 75 to report CO_2 emissions by fuel type from these combustion units.

Response: EPA acknowledges the commenter's concerns, and has addressed this issue in the final rule. Section 98.36(b)(7) of the final rule states that, for Tier 4 units, the annual CO_2 emissions will be reported for all fuels combined, and that any biogenic CO_2 emissions will also be reported separately. It also states that CH_4 and N_2O emissions are to be reported for each type of fuel combusted, calculated in accordance with §98.33(c). In §98.33(c)(3), EPA has specified that reporters using Tier 4 are to use the best available estimates of the annual heat input from each type of fuel combusted in the unit during the reporting year, excluding fuel used only for startup or ignition. This can be from CEMS data or engineering calculations. Using this data they are to calculate CH_4 and N_2O emissions for each fuel type.

In revising the final version of the rule, EPA has also added §98.36(d) to define data reporting requirements for units subject to Part 75, which requires total emissions by unit, not by fuel. EPA believes that these provisions in the final rule effectively address the concerns of the commenters.

Commenter Name: Alison A. Keane
Commenter Affiliation: National Paint & Coatings Association, Inc. (NPCA/FSCT)
Document Control Number: EPA-HQ-OAR-2008-0508-0593.1
Comment Excerpt Number: 10

Comment: Requiring submission after request within 7 days is unwarranted. While records maintained onsite will be available upon request – it will often take more time to compile and submit. EPA should provide a 30 day period in which to fulfill a data submission request. In addition, request for data submissions should only be made via hard copy mail – submission of these requests electronically may not always make it to the right facility or the right individual at the facility and the facility should not be held responsible for faulty electronic communications.

Response: EPA acknowledges the commenter's concerns. In Section 98.36(e)(3) of the final rule, EPA has allowed owners or operators 30 days from receipt of a written request for information to respond to that request.

EPA does not believe that it is necessary to specify that requests for data submissions be made via hard copy mail. EPA believes that electronic requests are sufficiently reliable.

Commenter Name: Michael DiMauro
Commenter Affiliation: Massachusetts Municipal Wholesale Electric Company (MMWEC)
Document Control Number: EPA-HQ-OAR-2008-0508-0580
Comment Excerpt Number: 12

Comment: The types of information that are considered "company records" for the purpose of documenting fuel usage under Tier I and II should be clarified. In particular: i. It should be verified that manually or automatically collected fuel flow data measured by certified or uncertified fuel meters qualify as "company records" of fuel usage suitable for use in Tier I or Tier II monitoring. A Unit that has a design heat input < 250 MMBtu should not be pushed into Tier III fuel sampling simply because fuel usage is determined from fuel meter flow records rather from fuel supplier shipment delivery slip records. ii. It should be verified that manually or automatically collected Oil Tank Drop measurements qualify as "company records" of oil fuel usage suitable for use in Tier I or Tier II monitoring. iii. It should be clarified that for sources that: (a) operate multiple oil fired stationary combustion units whose individual design heat inputs are < 250 MMBtu and whose combined design heat Inputs > 250 MMBtu/hr, and (b) who supply oil to these multiple stationary units from one or more non-dedicated Oil Storage tanks, it is acceptable to use fuel delivery invoices to document total oil usage for these combustion units, under the Tier I or Tier II monitoring schemes.

Response: EPA acknowledges the commenter's concerns, and has defined the term "company records" in §98.6 of the final rule. EPA believes that the revised definition provides appropriate guidance as to what records a facility may use to determine fuel consumption. EPA does not intend that the presence of a fuel flow meter will require a unit to calculate emissions using Tier 3. For units that use Tiers 1, 2, and 3 to calculate CO_2 mass emissions, the cumulative 250 mmBtu/hr heat input capacity limit on the aggregation of units into a group has been dropped. Rather, the 250 mmBtu/hr restriction applies only to the individual units in the group. Therefore, for reporting purposes, individual units with maximum rated heat input capacities of 250 mmBtu/hr or less may be aggregated without limit into a single group, provided that the Tier 4 methodology is not required for any of the units, and all units in the group use the same Tier for any common fuel(s) that they combust.

Commenter Name: J. Michael Kennedy
Commenter Affiliation: Florida Electric Power Coordinating Group
Document Control Number: EPA-HQ-OAR-2008-0508-0473.1
Comment Excerpt Number: 13

Comment: Under §98.36(b), EPA proposes to require unit level reporting of various pieces of information not only for Subpart C combustion sources, but also for ARP units. Although most of the information specified in §98.36(b) is not burdensome to report, the data required under (b)(5) would be for some units. Proposed §98.36(6)(5) would require the reporting of calculated CO_2, CH_4, and N_2O data for each fuel type combusted at the unit. Units using continuous monitoring methods, like CO_2/O_2 CEMS and volumetric flow monitors (to calculate heat input) generally do not employ instrumentation to record when a different fuel is being combusted. For example, a coal-fired unit that uses oil to startup would monitor CO_2/O_2 and volumetric flow all the way through the startup process and past the point when coal enters the boiler without recordation of when the change in fuel took place. Similarly, some oil and gas-fired units may switch between the two fuels, or even co-fire oil and gas, without recording which fuel type was responsible for the emissions and flow. For such units, it simply is not possible to provide estimates of emissions by fuel type without addition of what might be complicated, expensive, and otherwise unnecessary instrumentation. Therefore, FCG urges EPA to remove the provision from the rule.

Response: EPA acknowledges the commenter's concerns, and has addressed this issue in the final rule. Section 98.36(b)(7) of the final rule states that, for Tier 4 units, the annual CO_2 emissions will be reported for all fuels combined, and that any biogenic CO_2 emissions will also be reported separately. It also states that CH_4 and N_2O emissions are to be reported for each type of fuel combusted, calculated in accordance with §98.33(c). In §98.33(c)(3), EPA has specified that reporters using Tier 4 are to use the best available estimates of the annual heat input from each type of fuel combusted in the unit during the reporting year, excluding fuel used only for startup or ignition. This can be from CEMS data or engineering calculations. Using this data they are to calculate CH_4 and N_2O emissions for each fuel type.

In revising the final version of the rule, EPA has also added §98.36(d) to define data reporting requirements for units subject to Part 75, which requires total emissions by unit, not by fuel. EPA believes that these provisions in the final rule effectively address the concerns of the commenters.

Commenter Name: Kelly R. Carmichael
Commenter Affiliation: NiSource
Document Control Number: EPA-HQ-OAR-2008-0508-1080.2
Comment Excerpt Number: 13

Comment: NiSource supports the aggregation approaches for unit-level reporting identified in Part 98.36(c). Part 98.36(c)(1) allows aggregate reporting for up to 250 MMBtu/hr of combustion sources at a facility and Part 98.36(c)(3) allows multiple gas-fired or oil-fired units fed through a common fuel line to report combined emissions for those units. This aggregate reporting provides reasonable approaches to reporting detail while providing operators the opportunity to consider logical groupings within a facility. NiSource strongly supports these aggregate approaches for reporting combustion emissions.

Response: EPA appreciates the commenter's support. For units that use Tiers 1, 2, and 3 to calculate CO_2 mass emissions, the cumulative 250 mmBtu/hr heat input capacity limit on the aggregation of units into a group has been dropped. Rather, the 250 mmBtu/hr restriction applies only to the individual units in the group. Therefore, for reporting purposes, individual units with maximum rated heat input capacities of 250 mmBtu/hr or less may be aggregated without limit into a single group, provided that the Tier 4 methodology is not required for any of the units, and all units in the group use the same Tier for any common fuel(s) that they combust. Units with maximum rated heat inputs greater than 250 mmBtu/hr must report as individual units, unless they burn the same type of fuel (oil or gas) provided by a common pipe or supply line; in that case, the owner or operator may opt to use the common pipe reporting provisions in §98.36(c)(3). Units using Tier 4 must report as individual units unless they share a monitored common stack; in that case, the common stack reporting provisions of §98.36(c)(2) may be used.

Commenter Name: Kelly R. Carmichael
Commenter Affiliation: NiSource
Document Control Number: EPA-HQ-OAR-2008-0508-1080.2
Comment Excerpt Number: 14

Comment: To avoid confusion during implementation and provide reporting consistency, NiSource recommends that EPA specify the horsepower (hp) equivalent to 250 MMBtu/hr. Combustion capacity at many facilities is permitted based on horsepower rating rather than firing rate and presenting the horsepower equivalent will ensure that the aggregation threshold is consistently implemented for subject facilities. In our discussions with member companies of INGAA, NiSource agrees with INGAA recommendation that the rule indicate that aggregation for combustion reporting can be based on 250 MMBtu/hr or 30,000 hp. Similarly, the 30,000 hp equivalency to 250 MMBtu/hr should be used for defining whether a Tier 1 or Tier 2 approach can be used for an individual source (i.e., larger sources must use Tier 3 or Tier 4).

Response: EPA has not defined a horsepower equivalent to the maximum rated heat input capacity defined in §98.36 of the final rule. It is straightforward for an individual facility to carry out unit conversions as internal guides for applicability, and EPA may consider similar conversions as part of guidance to stakeholders. Nevertheless, having multiple thresholds in different units would add complexity to the applicability determination, going against the overwhelming majority of comments requesting more streamlining of the threshold determination.

Commenter Name: Traylor Champion
Commenter Affiliation: Georgia-Pacific, LLC (GP)
Document Control Number: EPA-HQ-OAR-2008-0508-0380.1
Comment Excerpt Number: 26

Comment: Notwithstanding our preferred approach of using the Tier 1 methodology on fuels coming across the fenceline, the common pipe aggregation should be expanded to solid fuels such as coal and petroleum coke. As with natural gas and oil, facilities that use solid fossil fuels track very closely the amount of fuel purchased and actually used by adjustments to inventory since it is, in most cases, a significant part of the overall energy cost. They also carefully monitor the heat content of these fuels to assure that the fuel meets specifications. Accounting for and reporting solid fuel usage more detailed than at the fenceline provides no additional value in terms of facility emissions, yet adds a significant and unnecessary reporting burden.

Response: EPA acknowledges the concerns of the commenter. The common pipe reporting option in §98.36(c)(3) applies only to liquid and gaseous fuels. However, the unit aggregation option in §98.36(c)(1) applies to units combusting any type of fuel, including solid fuel. In the final rule, the cumulative 250 mmBtu/hr heat input capacity limit on the aggregation of units into a group has been dropped. Rather, the 250 mmBtu/hr restriction applies only to the individual units in the group. Therefore, for reporting purposes, individual units with maximum rated heat input capacities of 250 mmBtu/hr or less may be aggregated without limit into a single group, provided that the Tier 4 methodology is not required for any of the units, and all units in the group use the same Tier for any common fuel(s) that they combust.

Commenter Name: Ron Downey
Commenter Affiliation: LWB Refractories
Document Control Number: EPA-HQ-OAR-2008-0508-0719.1
Comment Excerpt Number: 35

Comment: 40 C.F.R. 98.36 requires unit or process-specific reporting of combustion emissions. The physical configuration of some lime plants do not lend themselves to unit-specific emissions calculations because one fuel feed system may support multiple kilns. The Proposed Rule's objective to collect facility-level data is not undermined by permitting facility-wide reporting of combustion fuel emissions. The Proposed Rule should follow the Western Climate Initiative's Final Draft of Essential Requirements of Mandatory Reporting, which permits facility-wide reporting of combustion fuel emissions. In accordance with 40 C.F.R. 98.37, source can retain any unit-specific emissions information in company records and make it available for review upon request by EPA. Facility-wide reporting of combustion emissions satisfies EPA's objective of developing facility-wide emissions information, without requiring businesses in highly competitive industries to disclose highly sensitive confidential business information.

Response: See the Preamble, Section II. R., and the response to comment EPA-HQ-OAR-2008-0508-0520.1 excerpt 16 for EPA's response on CBI. Also see the response to the same comment, comment EPA-HQ-OAR-2008-0508-0520.1, excerpt 16 for the response to the need for unit-level data, additional flexibility EPA has provided for aggregation and common pipe configurations at facilities.

Commenter Name: Lorraine Krupa Gershman
Commenter Affiliation: American Chemistry Council (ACC)
Document Control Number: EPA-HQ-OAR-2008-0508-0423.2
Comment Excerpt Number: 73

Comment: In §98.36(d), the verification data is far greater than that required by any other rule. Instead of submitting this data annually and requiring excessive reporting, ACC recommends that facilities should be required to maintain this data and produce it upon request. In §98.36(d)(1)(i) requirements for verification data for Tier 3 methodology, where a process gas is being combusted, the submittal of daily data on quantity of fuel combusted, carbon content of the fuel, and molecular weight of the fuel is excessive. ACC recommends that monthly sampling be allowed unless and until a facility can show through a statistical analysis that a different and possibly less frequent sampling analysis may be appropriate. Further, these results should be shifted over to §98.37 Recordkeeping instead of requiring submittal of daily (or monthly) information for each of the variables used in the Tier 3 calculation methodology. At the most, EPA should not require reporting of more data than of monthly averages.

Response: EPA does not agree with the commenter's assertion that the verification data is far greater than that required by any other rule, or that the amount of unit-level data and verification information to be reported electronically is excessive, burdensome, or unnecessary. See the response to comment EPA-HQ-OAR-2008-0508-0520.1 excerpt 16 for EPA's response to the need for unit-level data, including additional flexibility EPA has provided for aggregation and common pipe configurations at facilities.

However, the final rule addresses some of the commenter's concerns. In particular, for gaseous fuels other than natural gas or biogas, the daily sampling requirement has been retained, but only for facilities with existing equipment in place that is capable of providing the data. Otherwise, weekly sampling is required. EPA is requiring this frequency because of the potential variability in process gas compared to commercial gaseous fuels. The commenter's suggestion to use statistical analysis to show that less frequent sampling is acceptable has merit. However, no details of the statistical method to be used for the demonstration were provided. Therefore, EPA has not incorporated the commenter's suggestion, but is willing to consider it in a future rulemaking, if an appropriate demonstration method is provided for Agency review.

Commenter Name: Marc J. Meteyer
Commenter Affiliation: Compressed Gas Association (CGA)
Document Control Number: EPA-HQ-OAR-2008-0508-0981.1
Comment Excerpt Number: 26

Comment: The proposed rule requires reporting of GHG emissions for each type of fuel combusted. It is not clear if the expectation is discrete, or combined, reporting of the GHG emissions for each/all fuel types. Separate reporting of GHG emissions from the combustion of each discrete fuel type increases the risk that confidential business information (operating rates, fuel choices, operating efficiencies) could be revealed in reports accessible to domestic and international competitors and customers of the regulated source. Further, when CO_2 emissions are calculated using the Tier 4 method, there is no way to distinguish which CO_2 emissions come from each individual fuels. CGA Comment: EPA should clarify that emission reporting is required only for the combined emissions from all fuels combusted. Reporting emissions for each fuel separately should not be required. Additionally, provisions to protect the confidentiality of all process, production and business- related information required under the rule should be strengthened. While CGA accepts that facility-level emissions cannot be protected from public disclosure, it strongly requests all other information should, by default, be considered confidential business information and afforded the utmost protection from public disclosure.

Response: EPA acknowledges the commenter's concerns, and has addressed this issue in the final rule. Units calculating emissions using Tiers 1, 2, or 3 must report emissions by fuel type. However, §98.36(b)(7) of the final rule states that, for Tier 4 units, the annual CO_2 emissions will be reported for all fuels combined, and that any biogenic CO_2 emissions will also be reported separately. It also states that CH_4 and N_2O emissions are to be reported for each type of fuel combusted, calculated in accordance with §98.33(c). In §98.33(c)(3), EPA has specified that reporters using Tier 4 are to use the best available estimates of the annual heat input from each type of fuel combusted in the unit during the reporting year, excluding fuel used only for startup or ignition. This can be from CEMS data or engineering calculations. Using this data they are to calculate CH_4 and N_2O emissions for each fuel type.

In revising the final version of the rule, EPA has also added §98.36(d) to define data reporting requirements for units subject to Part 75, which requires total emissions by unit, not by fuel. EPA believes that these provisions in the final rule effectively address the concerns of the commenters.

See the Preamble, Section II. R., and the response to comment EPA-HQ-OAR-2008-0508-0520.1 excerpt 16 for EPA's response on CBI.

Commenter Name: Juanita M. Bursley
Commenter Affiliation: GrafTech International Holdings Inc. Company (GrafTech)
Document Control Number: EPA-HQ-OAR-2008-0508-0686.1
Comment Excerpt Number: 26

Comment: GrafTech requests EPA to re-evaluate the selection of its proposed requirements for reporting unit-level data, to simplify the report and reduce the burden on the regulated community, particularly if a facility meets the criteria and opts to aggregate its smaller combustion units into "process-level" groups or combine units supplied by a common fuel supply piping configuration for reporting purposes. In the majority of cases, the Tier 1 or Tier 2 reporting methods would be acceptable to estimate emissions from these groups of combustion units. In particular, requiring the additional reporting of the unit types and maximum rated heat input of each unit is excessively burdensome, considering the likelihood that many reporting facilities have large numbers of fuel combustion units. Furthermore, requiring such detailed information would essentially negate the simplification provided by allowing the facility to aggregate multiple units for emissions reporting, and this information is not necessary to verify data. And lastly, GrafTech is concerned that in industries such as the carbon and manufactured graphite industry, which typically operate numerous fuel-fired process equipment, this level of detail would potentially provide what is considered proprietary information on production capabilities to competitors, putting companies with large production facilities in the U.S. that have to report at an economic disadvantage.

Response: See the Preamble, Section II. R., and the response to comment EPA-HQ-OAR-2008-0508-0520.1 excerpt 16 for EPA's response on CBI. Also see the response to the same comment, comment EPA-HQ-OAR-2008-0508-0520.1, excerpt 16 for the response to the need for unit-level data, additional flexibility EPA has provided for unit aggregation and common pipe configurations at facilities.

Commenter Name: Robert Rouse
Commenter Affiliation: The Dow Chemical Company
Document Control Number: EPA-HQ-OAR-2008-0508-0533.1
Comment Excerpt Number: 26

Comment: Dow Suggests that the Type and Quantity of Fuel Combusted in Each Source Should Be Relocated to Section 98.37 (Recordkeeping). In 98.36(b) and (c), there are situations when the fuel-type might be Confidential Business Information (CBI). For example, a facility may not want to identify to competitors how much process off-gas is recovered and burned. Individual emission units should not be required to report their fuel type, and EPA should not require it to be reported. This detail should be moved from the reporting section to the recordkeeping section of this rule. Dow Supports the Reporting Alternative for Stationary Combustion Units for Small Units and Suggests Raising the Aggregate Limit to < 750 mm Btu/hr. Dow supports the general concept of aggregating small combustion units as proposed in 98.36(c)(1). Dow suggests that large petrochemical complexes be able to combine sources together as long as the maximum rated heat input capacity of each unit is < 250 mm Btu/hr and the aggregate maximum rate heat input capacity of the units does not exceed 750 mm Btu/hr. The proposed aggregate limit of 250 mm Btu/hr will result in some larger complexes still having to report a number of smaller sources on a unit-level basis. Dow Supports EPA's Proposed Common Pipe Configuration Concept. Dow supports the general concept of reporting combined emissions from units served by common supply line as outlined in 98.36(c)(3). Dow Suggests that the Majority of the Items Listed under Proposed 98.36(d) "Verification Data" be Removed from the Reporting Section of the Rule and Relocated to the Recordkeeping Portion of the Rule in 98.37. General - The verification data is more excessive than is submitted under any other existing State or Federal emissions inventory rule. Dow realizes that EPA has chosen the position of self-certification with EPA verification. Dow supports this position and suggests that this goal can be accomplished by either a review of records by agencies or the submittal of the details contained in 98.36(d) for "one" of the regulated combustion sources at a site. In general, instead of submitting this data annually and requiring excessive reporting, facilities should be required to maintain this data and produce it upon request. EPA's proposed reporting requirements are unnecessarily burdensome, far beyond what is required for future policy decisions. Specific Comments - In 98.36(d)(1)(iii)(A - E), the requirements for verification data for Tier 3 methodology, where a process gas is being combusted, the submittal of daily data on quantity of fuel combusted, carbon content of the fuel, and molecular weight of the fuel are excessive. Dow recommends that monthly sampling be allowed unless and until a facility can show through a statistical analysis that a different and possibly less frequent sampling analysis may be appropriate. Further, these results should be moved to 98.37 on Recordkeeping instead of requiring submittal of daily (or monthly) information for each of the variables used in the Tier 2 calculation methodology. At the most, EPA should not require reporting of more than monthly average values. In 98.36(d)(1)(iii)(F) and (I), the requirement for submittal of the results of the initial calibrations and periodic recalibrations of the fuel flow meters used to measure the amount of fuel combusted is another example of a requirement that should be a recordkeeping requirement only. These calibration records do not lend themselves well to electronic reporting, and submittal of this information for all flow meters is not necessary for EPA to verify the quality of the GHG emissions information provided. In 98.36(d)(iv)(F), Dow suggests that EPA move the requirements to report linearity checks and cylinder gas audits to the recordkeeping portion of this rule. Reporting of RATA results should be clarified such that a summary report of the results vs. the details of the RATA evaluation is acceptable. Dow Suggests Revisions to Proposed 98.36(d)(2). EPA's proposal requires an entity to respond within 7 days of receiving a written request or email. Dow suggests that this response time be extended to 30 days to ensure that the request is forwarded to the proper personnel and that they have ample time respond to such requests. This would alleviate complications that may arise if the appropriate personnel do not receive the requests immediately or have off-site commitments for a short period of time (such as auditing or project work or even vacation).

Response: See the Preamble, Section II. R., and the response to comment EPA-HQ-OAR-2008-0508-0520.1 excerpt 16 for EPA's response on CBI.

EPA does not agree with the commenter's assertion that the amount of unit-level data and verification information to be reported electronically is excessive, burdensome, or unnecessary. For this mandatory GHG emissions reporting rule, two main approaches to data verification were considered, i.e., EPA verification and third-party verification. EPA decided on the former approach. In view of this, the reporting of additional, unit-level information is deemed necessary to provide assurance that the reported facility-wide GHG emissions data are both credible and accurate. However, as explained in the paragraphs below, EPA has made a number of significant adjustments in the final rule to the data reporting requirements of §98.36, both to clarify those requirements and to reduce the reporting burden.

For units that use Tiers 1, 2, and 3 to calculate CO_2 mass emissions, the cumulative 250 mmBtu/hr heat input capacity limit on the aggregation of units into a group has been dropped. Rather, the 250 mmBtu/hr restriction applies only to the individual units in the group. Therefore, for reporting purposes, individual units with maximum rated heat input capacities of 250 mmBtu/hr or less may be aggregated without limit into a single group, provided that the Tier 4 methodology is not required for any of the units, and all units in the group use the same Tier for any common fuel(s) that they combust. Units with maximum rated heat inputs greater than 250 mmBtu/hr using Tiers 1, 2, and 3 must report as individual units, unless they burn the same type of fuel provided by a common pipe or supply line; in that case, the owner or operator may opt to use the common pipe reporting provisions in §98.36(c)(3). Units using Tier 4 must report as individual units unless they share a monitored common stack; in that case, the common stack reporting provisions of §98.36(c)(2) may be used.

The Tier 2 and 3 fuel sampling requirements in §98.34 have been substantially relaxed. EPA believes that the provisions in the final rule will pose less of a burden on reporters.

The supplementary verification information requirements of §98.36(e) have been clarified and, in some cases, differ substantively from the proposed rule. Paragraph (e)(1) in §98.36 clearly states that no additional verification information is required for sources that monitor and report emissions and heat input data using Part 75. For sources using Tiers 1, 2, 3, and 4, the final rule streamlines some of the reporting. Sources using Tier 3 are required to report only monthly averages of the fuel carbon content and molecular weight rather than the proposed requirement to submit the results of each individual determination. Sources that use Tier 4 are required to report quarterly cumulative CO_2 mass emissions, rather than the proposed requirement to report daily CO_2 emissions. Also, to address concerns raised by some of the commenters, the certification and QA test reporting requirements of Tiers 3 and 4 have been clarified. The final rule requires only that records be kept of the CEMS and fuel flow meter QA tests and the methods used. The test results are not required to be reported electronically or in hard copy, but must be made available to EPA and/or the State agencies upon request. In §98.36(e)(3) of the final rule, EPA has allowed owners or operators 30 days from receipt of a written request for information to respond to that request.

Regarding the use of statistical analysis to justify less frequent fuel sampling, the suggestion has merit. However, no details of the statistical method to be used for such a demonstration were provided. Therefore, EPA has not incorporated the commenter's suggestion, but is willing to consider it in a future rulemaking, if an appropriate demonstration method is provided for Agency review.

Commenter Name: Marc J. Meteyer
Commenter Affiliation: Compressed Gas Association (CGA)
Document Control Number: EPA-HQ-OAR-2008-0508-0981.1
Comment Excerpt Number: 27

Comment: The proposed rule offers the option to calculate and report emissions for aggregated units under the provisions of §98.36(c)(1), (2), and (3). These are effective methods by which a source can streamline the process measurement, emission calculation, and emission reporting requirements. CGA Comment: CGA strongly support the optional aggregation provisions and encourages EPA to consider expanding the applicability of such options. For example, eliminating the restriction of the aggregated maximum capacity of 250 mm BTU/hr under §98.36(c)(1) would not compromise the accuracy or completeness of the reported data, but could reduce the emission calculation and reporting burden and provide some additional protection to confidential business information.

Response: EPA appreciates the commenter's support, and has made a number of significant adjustments in the final rule to the data reporting requirements of §98.36, both to clarify those requirements and to reduce the reporting burden. For units that use Tiers 1, 2, and 3 to calculate CO_2 mass emissions, the cumulative 250 mmBtu/hr heat input capacity limit on the aggregation of units into a group has been dropped. Rather, the 250 mmBtu/hr restriction applies only to the individual units in the group. Therefore, for reporting purposes, individual units with maximum rated heat input capacities of 250 mmBtu/hr or less may be aggregated without limit into a single group, provided that the Tier 4 methodology is not required for any of the units, and all units in the group use the same Tier for any common fuel(s) that they combust. Units with maximum rated heat inputs greater than 250 mmBtu/hr using Tiers 1, 2, and 3 must report as individual units, unless they burn the same type of fuel provided by a common pipe or supply line; in that case, the owner or operator may opt to use the highest Tier required for a grouped unit for the calculation method with the common pipe reporting provisions in §98.36(c)(3). Units using Tier 4 must report as individual units unless they share a monitored common stack; in that case, the common stack reporting provisions of §98.36(c)(2) may be used.

Commenter Name: Marc J. Meteyer
Commenter Affiliation: Compressed Gas Association (CGA)
Document Control Number: EPA-HQ-OAR-2008-0508-0981.1
Comment Excerpt Number: 28

Comment: The proposed rule describes in detail all the information required to be reported in order to verify the reported GHG emissions. The data compilation for all the information EPA seeks under §98.36(d) is extremely burdensome for regulated sources. While some of this information is used in order to develop, and assure the accuracy of, the emissions estimate, reporting all of this information is not necessary. In many cases, the necessity of this information is questionable, based on the rule's intention to develop an annual emissions estimate. Examples include §98.36(d)(1)(iv)(A) – number of operating hours per day of a particular emission source and §98.36(d)(1)(iv)(C) – daily CO_2 emissions (when an annual total is the rule's objective). Reporting at this level of detail also increases the risk that confidential business information could be revealed in reports accessible to domestic and international competitors and customers of the regulated source. CGA Comment: Regulated sources should only be required to maintain the appropriate information that supports the emissions calculations and reporting basis, and make this information available upon request of EPA. Reporting of any information unrelated to emissions should not be required. All process, production and business-related information required to be reported under provisions to insure the veracity of the reported emissions should be afforded the maximum confidentiality protections.

Response: See the Preamble, Section II. R., and the response to comment EPA-HQ-OAR-2008-0508-0520.1 excerpt 16 for EPA's response on CBI. Also see the same response to comment EPA-HQ-OAR-2008-0508-0520.1 excerpt 16 for the response to the need for unit-level data, including additional flexibility EPA has provided for aggregation and common pipe configurations at facilities.

EPA has not finalized the requirements to report daily CO_2 emissions or the number of unit operating hours per day. Sections 98.36(e)(2)(vi)(A) and (B) require facilities to report only the number of annual unit operating hours and the cumulative CO_2 mass emissions in each quarter of the reporting year.

Commenter Name: Marc J. Meteyer
Commenter Affiliation: Compressed Gas Association (CGA)
Document Control Number: EPA-HQ-OAR-2008-0508-0981.1
Comment Excerpt Number: 29

Comment: The proposed rule appears to require the source report its CEMS relative accuracy test audit (RATA) results. It is not clear if EPA would be satisfied by a singular statement that the CEMS passed or failed the RATA, or if the intent is to submit the entire RATA report which, in addition to being many pages in length, often contains confidential business information. CGA Comment: Clarify that EPA does not want a source to submit its entire RATA report and instead, will be satisfied with a singular statement that the RATA was conducted (by whom and on what date) and the results of the RATA, as a pass/fail designation.

Response: EPA acknowledges the commenter's concerns, and has included additional language to §98.36(e)(2)(iv)(E) and (F), clarifying that reporters are required to submit the dates and *summarized* results of the QA tests (e.g., RATAs) performed during the reporting year. The rule does not require facilities to submit detailed test run information or hard copy test reports.

Commenter Name: Kimberly S. Lagomarsino
Commenter Affiliation: Mississippi Lime
Document Control Number: EPA-HQ-OAR-2008-0508-1568
Comment Excerpt Number: 24

Comment: 40 CFR 98.36(d) requires that monthly and daily data details be included in the reported data. It is Mississippi Lime Company's understanding that the annual GHG reports to EPA may be filed electronically. As such, the requested data details will involve manually entering significant amounts of data; a redundant endeavor of capturing data previously generated through facility accounting mechanisms. Suggestion: Please revise 98.36(d) to allow for detailed information to be maintained in on-site records available for review upon request versus being submitted in the annual reports.

Response: EPA intends to develop electronic reporting tools that will reduce the manual entry burden, particularly for data that are used in multiple calculations. EPA also intends to explore bulk upload options that take advantage of facilities' existing electronic data management systems. See the response to comment EPA-HQ-OAR-2008-0508-0520.1 excerpt 16 for the response to the need for unit-level data, including additional flexibility EPA has provided for unit aggregation and common pipe configurations at facilities.

Commenter Name: Sarah B. King
Commenter Affiliation: DuPont Company
Document Control Number: EPA-HQ-OAR-2008-0508-0604.1
Comment Excerpt Number: 31

Comment: EPA should modify §98.36(b) and (c) to allow a facility to report only the total CO_2 for a facility instead of unit-specific calculation and reporting. This is advantageous to EPA as a Registry calculation tool because it will capture smaller sources and make the total Registry more complete. Many facilities do not currently have the meters installed that would be necessary to perform unit-by-unit calculations. Even those that have unit metering capability primarily utilize them for rough cost allocations. The additional calibration and maintenance requirements and the need for uninterrupted operation necessary to comply with the proposed rule are additional examples of how the proposed approach to such calculations would be burdensome and excessive, while not adding to the overall use of the information to develop a greenhouse gas inventory.

Response: The purpose of the rule is not solely to develop a GHG inventory, but to inform the development of future climate policy under the Clean Air Act. See the response to comment EPA-HQ-OAR-2008-0508-0520.1 excerpt 16 for the response to the need for unit-level data, including additional flexibility EPA has provided for aggregation and common pipe configurations at facilities.

Commenter Name: Juanita M. Bursley
Commenter Affiliation: GrafTech International Holdings Inc. Company (GrafTech)
Document Control Number: EPA-HQ-OAR-2008-0508-0686.1
Comment Excerpt Number: 23

Comment: GrafTech agrees with the EPA's proposal under §98.36(c)(1) and (c)(3), to allow a facility to aggregate combustion units for the purpose of simplifying its calculations for estimating GHG emissions. According to this proposed language, a facility can 1) aggregate smaller combustion units into "process-level" groups, as long as the combined maximum rated heat input capacity is < 250 mmBtu/hr per group and provided the amount of fuel use can be accurately quantified, or 2) combine units supplied by a common fuel supply piping configuration if there is a calibrated fuel flow meter, with no restriction on the total maximum rated heat input capacity of the group. In fact, GrafTech believes that aggregating smaller combustion units into "process-level" groups should also not be limited to groups having combined maximum rated heat input capacity is < 250 mmBtu/hr, provided the facility has sufficient monitoring/metering systems to accurately quantify the amount of fuel used. While this maximum rated heat input capacity may be consistent with the definition of a large unit under other regulatory programs, this added limitation in this case will not improve the quality of GHG emissions data, but may cause a facility the unnecessary burden to add or upgrade current fuel metering systems. This flexibility will allow each facility to monitor fuel use, collect data and calculate emissions in the most efficient way for its operations, without negatively affecting the accuracy or consistency of the submitted emissions data, and without unnecessary added costs of installing or upgrading fuel metering systems. However, this flexibility will be wholly negated if the facility has to install CEMS simply because a combustion unit exceeds 1,000 hours of operations (see above comments). Furthermore, GrafTech believes it is commonplace for a reporting facility to have multiple combustion units supplied by a common fuel supply piping configuration, where the primary, or in many cases the only, fuel flow meter is the billing meter owned and operated by the fuel supplier. In this case, GrafTech believes that the supplier, rather than the combustion facility, should be responsible under this GHG reporting rule for meeting calibration and all the other requirements associated with maintaining this fuel use monitoring system in good operating order and retaining the required recordkeeping for documentation purposes. The amount of fuel used, in this case, should be quantified through the use of purchase receipts or similar billing records provided to the facility by the fuel supplier. Since the supplier's metering system is used for billing purposes, it would be expected to be properly maintained so as to provide accurate measurements of the facility's fuel use. As nearly all GHG reporting facilities will have such fuel purchase records from the supplier, this will be the most efficient and least burdensome method for facilities to obtain fuel usage data.

Response: See the response to comment EPA-HQ-OAR-2008-0508-0520.1 excerpt 16 for the response to the need for unit-level data, including additional flexibility EPA has provided for aggregation and common pipe configurations at facilities.

EPA has made a number of significant adjustments in the final rule to the data reporting requirements of §98.36, both to clarify those requirements and to reduce the reporting burden.

For units that use Tiers 1, 2, and 3 to calculate CO_2 mass emissions, the cumulative 250 mmBtu/hr heat input capacity limit on the aggregation of units into a group has been dropped. Rather, the 250 mmBtu/hr restriction applies only to the individual units in the group. Therefore, for reporting purposes, individual units with maximum rated heat input capacities of 250 mmBtu/hr or less may be aggregated without limit into a single group, provided that the Tier 4 methodology is not required for any of the units, and all units in the group use the same Tier for any common fuel(s) that they combust. Units with maximum rated heat inputs greater than 250 mmBtu/hr must report as individual units, unless they burn the same type of fuel (oil or gas) provided by a common pipe or supply line; in that case, the owner or operator may opt to use the highest Tier required for a grouped unit for the calculation method with the common pipe reporting provisions in §98.36(c)(3). Units using Tier 4 must report as individual units unless they share a monitored common stack; in that case, the common stack reporting provisions of §98.36(c)(2) may be used.

Units are not required to install CEMS unless all of the criteria under §98.33(b)(4)(ii) are met.

The rule has been clarified to affirm that the use of fuel sampling results provided by the fuel supplier is permissible, and that the use of fuel billing records to quantify fuel consumption is also allowed.

Also, EPA has revised Subpart C to clarify that facilities are not responsible for the calibration and on-going QA of fuel billing meters provided that the fuel supplier and the unit(s) combusting the fuel do not have any common owners and are not owned by subsidiaries or affiliates of the same company.

Commenter Name: Lauren E. Freeman
Commenter Affiliation: Hunton & Williams LLP
Document Control Number: EPA-HQ-OAR-2008-0508-0493.1
Comment Excerpt Number: 36

Comment: In §98.36(b), EPA proposes to require unit-level reporting of various items of information not only for Subpart C combustion sources, but for all units reporting under Subpart D. See Proposed §98.46. Although much of the information specified in §98.36(b) is not particularly burdensome to report, reporting the data that EPA proposes to require under §98.36(b)(5) would be burdensome for some units. Proposed §98.36(b)(5) would require the reporting of calculated CO_2, CH_4, and N_2O data for each fuel type combusted at the unit. Units using continuous monitoring methods, like CO_2 or O_2 CEMS and volumetric flow monitors (to calculate heat input), generally do not employ instrumentation to record when a different fuel is being combusted. For example, a coal-fired unit that uses oil to startup would monitor CO_2/O_2 and volumetric flow all the way through the startup process and past the point when coal enters the boiler without recording when the change in fuel took place. Similarly, some oil- and gas-fired units may switch between the two fuels, or even co-fire oil and gas, without recording which fuel or fuels were responsible for the emissions and flow. For such units, it simply is not possible to provide estimates of emissions by fuel type without addition of what might be complicated, expensive, and otherwise unnecessary instrumentation. Nor does UARG understand why such data are needed to fulfill Congress' mandate. EPA should remove this proposed provision or limit its application to units that already have the instrumentation or other means to make the calculation. If EPA retains the proposed requirement, EPA must describe why the information is needed, estimate the costs of gathering this information, and provide sufficient time for installation of equipment.

Response: EPA acknowledges the commenter's concerns, and has addressed this issue in the final rule. Section 98.36(b)(7) of the final rule states that, for Tier 4 units, the annual CO_2 emissions will be reported for all fuels combined, and that any biogenic CO_2 emissions will also be reported separately. It also states that CH_4 and N_2O emissions are to be reported for each type of fuel combusted, calculated in accordance with §98.33(c). In §98.33(c)(3), EPA has specified that reporters using Tier 4 are to use the best available estimates of the annual heat input from each type of fuel combusted in the unit during the reporting year, excluding fuel used only for startup or ignition. This can be from CEMS data or engineering calculations. Using this data they are to calculate CH_4 and N_2O emissions for each fuel type.

In revising the final version of the rule, EPA has also added §98.36(d) to define data reporting requirements for units subject to Part 75, which requires total emissions by unit, not by fuel. EPA believes that these provisions in the final rule effectively address the concerns of the commenters.

Commenter Name: Ron Downey
Commenter Affiliation: LWB Refractories
Document Control Number: EPA-HQ-OAR-2008-0508-0719.1
Comment Excerpt Number: 37

Comment: 40 C.F.R. 98.36(d)(1)(i) and (ii) requires sources to report fuel usage in short tons for solid fuels. However, 40 C.F.R. 98.36(d)((1)(iii) requires sources to report the amount of fuel combusted in metric tons. LWB recommends that EPA revise the Proposed Rule to require sources using the Tier 1, 2, and 3 calculation methodologies to report fuel usage in metric tons, to coincide with sector reporting. If this comment is accepted, the emission factors in Table C-1 should be updated reflect "mmBtu/metric ton."

Response: EPA believes that it is appropriate to report solid fuel usage in short tons. EPA has revised the Tier 3 reporting requirements in §98.36 to require reporting fuel usage in short tons for solid fuels, consistent with the other Tiers.

Commenter Name: Fiji George
Commenter Affiliation: El Paso Corporation
Document Control Number: EPA-HQ-OAR-2008-0508-0398.1
Comment Excerpt Number: 43

Comment: El Paso fully supports the aggregation of small combustion units that have a combined maximum rated heat input capacity of 250 mmBtu/hr or less to simplify unit-level reporting.

Response: EPA appreciates the commenter's support, and has made a number of significant adjustments in the final rule to the data reporting requirements of §98.36, both to clarify those requirements and to reduce the reporting burden. For units that use Tiers 1, 2, and 3 to calculate CO_2 mass emissions, the cumulative 250 mmBtu/hr heat input capacity limit on the aggregation of units into a group has been dropped. Rather, the 250 mmBtu/hr restriction applies only to the individual units in the group. Therefore, for reporting purposes, individual units with maximum rated heat input capacities of 250 mmBtu/hr or less may be aggregated without limit into a single group, provided that the Tier 4 methodology is not required for any of the units, and all units in the group use the same Tier for any common fuel(s) that they combust.

Commenter Name: See Table 5
Commenter Affiliation:
Document Control Number: EPA-HQ-OAR-2008-0508-0480.1
Comment Excerpt Number: 44

Comment: Section 98.36(d)(2) identifies the requirements for operator response to agency requests regarding methods for quantifying fuel consumption and requires a response within 7 days of receipt of a written request. INGAA recommends that this requirement be revised to allow at least two weeks for such a response. A seven day response time is not adequate when considering the timing involved to review and process the request. For example, if key personnel are on business travel or otherwise out of the office for only a few days, that could severely hinder the ability to respond within 7 days. Two weeks or more should be allowed and this schedule is still indicative of an expeditious response to an agency request.

Response: EPA acknowledges the commenter's concerns. In §98.36(e)(3) of the final rule, EPA has allowed owners or operators 30 days from receipt of a written request for information to respond to that request.

Commenter Name: Fiji George
Commenter Affiliation: El Paso Corporation
Document Control Number: EPA-HQ-OAR-2008-0508-0398.1
Comment Excerpt Number: 44

Comment: §98.36(d)(2) requires that facilities submit a response (explanation) to any written request from the administrator within seven days of receipt of such request. Depending on the severity and complexity of the request it may not be possible to complete a proper response in seven days. El Paso recommends the administrator provide at least ten business days to respond and the option to request an automatic, 30-day extension if reasonably necessary in light of the nature and extent of the required response.

Response: EPA acknowledges the commenter's concerns. In §98.36(e)(3) of the final rule, EPA has allowed owners or operators 30 days from receipt of a written request for information to respond to that request.

Commenter Name: Gregory A. Wilkins
Commenter Affiliation: Marathon Oil Corporation
Document Control Number: EPA-HQ-OAR-2008-0508-0712.1
Comment Excerpt Number: 53

Comment: Marathon supports EPA's proposal that facilities may group units that burn a common fuel if the group does not exceed 250 mmBtu/hr. There is no limit to the number of groups allowed per facility. This will help reduce cost by allowing very small individual stationary sources like engines (assuming they are not exempted from this rule) to be aggregated together and estimated one time, EPA states in the Preamble that for liquid and gas fired units smaller than 250 mmBtufhr, the use of Tier 1 and 2 methodology is allowed if emission factors arc listed by the EPA. Tier 1 and 2 use default or measured heating value, default CO_2 factors and measured or estimated fuel consumption.

Response: EPA appreciates the commenter's support, and has made a number of significant adjustments in the final rule to the data reporting requirements of §98.36, both to clarify those requirements and to reduce the reporting burden. For units that use Tiers 1, 2, and 3 to calculate CO_2 mass emissions, the cumulative 250 mmBtu/hr heat input capacity limit on the aggregation of units into a group has been dropped. Rather, the 250 mmBtu/hr restriction applies only to the individual units in the group. Therefore, for reporting purposes, individual units with maximum rated heat input capacities of 250 mmBtu/hr or less may be aggregated without limit into a single group, provided that the Tier 4 methodology is not required for any of the units, and all units in the group use the same Tier for any common fuel(s) that they combust.

Commenter Name: Gregory A. Wilkins
Commenter Affiliation: Marathon Oil Corporation
Document Control Number: EPA-HQ-OAR-2008-0508-0712.1
Comment Excerpt Number: 57

Comment: Marathon opposes the extensive additional reporting requirements required by Subpart C. EPA is proposing to require additional facility level information like unit types, maximum rated heat capacity for each unit, type and amount of fuel combusted by each unit, and unit level total GHG emissions. Other reporting requirements include all fuel carbon content values, information on substitute values, and flow meter calibration information. For one facility this could get very burdensome for every carbon content sample alone. Marathon does not see the value in reporting this information as it is not essential for anything besides verification of emission calculation (which was discussed previously in the comments). Marathon reminds EPA that with the common pipe allowance it will be almost impossible to determine fuel use and corresponding GHG emissions by unit if multiple units are supplied from a single fuel drum. Marathon proposes that these reporting requirements be removed from this subpart and instead allow for activity and sampling information to be kept as records by the facility using current data collection methods. This information could then be made available to EPA if they were to conduct an inspection.

Response: See the response to comment EPA-HQ-OAR-2008-0508-0520.1 excerpt 16 for the response to the need for unit-level data, including additional flexibility EPA has provided for aggregation and common pipe configurations at facilities.

EPA notes that the supplementary verification information requirements of §98.36(e) have been clarified and, in some cases, differ substantively from the proposed rule. Paragraph (e)(1) in §98.36 clearly states that no additional verification information is required for sources that monitor and report emissions and heat input data using Part 75. For sources using Tiers 1, 2, 3, and 4, the final rule streamlines some of the reporting. Sources using Tier 3 are required to report only monthly averages of the fuel carbon content and molecular weight rather than the proposed requirement to submit the results of each individual determination.

Commenter Name: See Table 3
Commenter Affiliation:
Document Control Number: EPA-HQ-OAR-2008-0508-0433.2
Comment Excerpt Number: 65

Comment: The text incorrectly refers to Equation C-14, should be C-13.

Response: EPA has corrected this error in the final rule.

Commenter Name: Ron Downey
Commenter Affiliation: LWB Refractories
Document Control Number: EPA-HQ-OAR-2008-0508-0719.1
Comment Excerpt Number: 30

Comment: Sources are required to report the maximum rated heat input capacity of combustion units, in mmBtu/hr for boilers, combustion turbines, engines, and process heaters only. 40 C.F.R. 98.36(b)(3). LWB requests clarification that the maximum rated heat input capacity of a unit is equal to the design capacity of the unit. We also would like confirmation that the term "process heaters" refers to all combustion equipment used to provide heat for the process that has a nameplate capacity.

Response: EPA believes the terms "maximum rated heat input capacity" and "design capacity" are equivalent and that both refer to the maximum amount of fuel of known Btu content that a unit is capable of combusting on a steady state basis, as of the initial installation of the unit, as specified by the manufacturer.

EPA does not believe that any additional language is necessary to clarify the term "process heaters." EPA uses the term "process heaters" to refer to a wide variety of devices in which heat is transferred indirectly to a process material, but do not produce electrical or steam load. Nameplate capacity is not one of the necessary criteria for a combustion source to be included in this category.

Commenter Name: Renae Schmidt
Commenter Affiliation: CITGO Petroleum Corporation
Document Control Number: EPA-HQ-OAR-2008-0508-0726.1
Comment Excerpt Number: 15

Comment: CITGO assumes that the aggregation of small units §98.36(cXl) applies to Tier 2 combustion sources with a common stack. A note of this understanding is recommended in §98.36(c)(2) paragraph for Monitored common stack configurations.

Response: It is EPA's intent that the common stack provisions in §98.36(c)(2) be used only for Tier 4 units using CEMS at the common stack. EPA has substantially revised §98.36(c)(l). According to the final rule, individual units with maximum rated heat input capacities of 250 mmBtu/hr or less may be aggregated without limit into a single group, provided that the Tier 4 methodology is not required for any of the units, and all units in the group use the same Tier for any common fuel(s) that they combust. EPA does not believe that any further language is necessary to clarify that units meeting these requirements and sharing a common stack may be aggregated according to §98.36(c)(l).

Commenter Name: J. P. Blackford
Commenter Affiliation: American Public Power Association (APPA)
Document Control Number: EPA-HQ-OAR-2008-0508-0661.1
Comment Excerpt Number: 1

Comment: APPA supports the flexibility allowed by the Draft Rule for data aggregation, as it is generally less onerous for reporting entities and has no major objections with the level of reporting aggregation included in the Draft Rule. In order to calculate the aggregated emissions, specific data from individual sources will need to be collected and managed. APPA does offer the suggestion that while in most cases multiple units may share a single stack, there are also some configurations at our member utilities where a single unit has multiple stacks (one example is a Pratt and Whitney "Twin Pack" which has two turbines and two stacks but is one unit). Since these units use natural gas as their fuel source, this issue would not be of significance at this time, but, it is offered to inform EPA of some alternate configurations for EGUs.

Response: EPA appreciates this comment, and is aware of less common unit/stack configurations such as the one identified by the commenter.

Commenter Name: Jeffrey A. Sitler
Commenter Affiliation: University of Virginia (UVA)
Document Control Number: EPA-HQ-OAR-2008-0508-0675.1
Comment Excerpt Number: 4

Comment: When aggregating small units as described in §98.36(c)(1), is there a limit to the number of units that can be aggregated into a group or is the only requirement that the aggregate maximum rated heat input capacity of all units in the group does not exceed 250mmBtu/hr?

Response: EPA acknowledges the commenter's concerns, and believes that the final rule includes further clarification on this topic. The rule language does not limit aggregation to a specific number of units. However, EPA has made a number of significant adjustments in the final rule to the data reporting requirements of §98.36 to clarify reporting requirements and to reduce the reporting burden for aggregated units.

For units that use Tiers 1, 2, and 3 to calculate CO_2 mass emissions, the cumulative 250 mmBtu/hr heat input capacity limit on the aggregation of units into a group has been dropped. Rather, the 250 mmBtu/hr restriction applies only to the individual units in the group. Therefore, for reporting purposes, individual units with maximum rated heat input capacities of 250 mmBtu/hr or less may be aggregated without limit into a single group, provided that the Tier 4 methodology is not required for any of the units, and all units in the group use the same Tier for any common fuel(s) that they combust. Units with maximum rated heat inputs greater than 250 mmBtu/hr using must report as individual units, unless they burn the same type of fuel provided by a common pipe or supply line; in that case, the owner or operator may opt to use the highest Tier required for a grouped unit for the calculation method and the common pipe reporting provisions in §98.36(c)(3). Units using Tier 4 must report as individual units unless they share a monitored common stack; in that case, the common stack reporting provisions of §98.36(c)(2) may be used.

Commenter Name: Rhea Hale
Commenter Affiliation: American Forest & Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2008-0508-0909.1
Comment Excerpt Number: 5

Comment: AF&PA agrees with EPA's inclusion of the provisions in section 98.36(c) Reporting Alternatives for Stationary Combustion Units. These provisions allow the use of common pipe configurations and monitored common stack configurations options would preclude the need to install fuel meters on individual units. These options should be allowed for all combustion units at a facility provided they meet the requirements of 98.36(c). It is extremely important to retain these provisions as facilities would need to schedule the installation of fuel meters on individual combustion units in order for the meters to be operational at the start of the 2010 reporting period. Installation of such meters would need to take place during scheduled mill outages, many of which occur on a greater than 12 month rotation schedule particularly for large combustion units. For example, a pulp mill that experienced major outage in May of 2009 may not see another major outage until fall of 2010, well after the collection of GHG data is to begin. In order to comply with the reporting rule, a compliant GHG estimation system needs to be in place by January 1, 2010 (see Initial Reporting Year comments below). A second GHG reporting system would need to be implemented for use after January 1, 2011. It is far more cost and resource effective to create a single information collection and reporting system to commence after appropriate equipment can be installed (e.g., in 2010 for use in 2011), rather than to do so twice (once for 2010 and then again for 2011). A Tier 1 type system could be installed and operated beginning in 2010. The more sophisticated, expensive and unnecessary systems (Tier 2, 3 and 4) could not.

Response: See the Preamble, Section II. G., for the response on the selection of the initial reporting year.

The final rule requires data collection for calendar year 2010, but has been changed since proposal to allow use of best available monitoring methods for the first part of 2010. Furthermore, the commenter should note that the final rule does not require fuel flow meters used for Tier 3 calculations to be calibrated until January 1, 2011.

The final rule includes further clarification and flexibility regarding aggregation and common pipe provisions that will reduce the burden on sources. EPA has retained the provision requiring fuel use in a common pipe configuration to be accurately measured by a calibrated fuel flow meter, and has clarified that Tier 3 methods are to be used for all common pipe configurations. Units using Tier 4 CEMS, may also use the common stack reporting provisions of §98.36(c)(2).

Commenter Name: Sarah B. King
Commenter Affiliation: DuPont Company
Document Control Number: EPA-HQ-OAR-2008-0508-0604.1
Comment Excerpt Number: 7

Comment: EPA proposes to require a response to a written request within 7 days. Such response time is unreasonable and unnecessary. Furthermore, the lack of immediate availability of such data poses no threat to human health and the environment as GHG emissions and climate change are not acute issues, but manifest over the long-term. EPA should allow facilities a reasonable period of time – a minimum of 30 days – to respond to such requests. EPA should also allow a further extension if the facility has extenuating circumstances.

Response: EPA acknowledges the commenter's concerns. In §98.36(e)(3) of the final rule, EPA has allowed owners or operators 30 days from receipt of a written request for information to respond to that request.

Commenter Name: John M. McManus
Commenter Affiliation: American Electric Power
Document Control Number: EPA-HQ-OAR-2008-0508-0725.1
Comment Excerpt Number: 10

Comment: AEP has a concern that §98.46(a) would subject electric generation facilities that are subject to the ARP to §98.36(b), which would require unit level reporting of various pieces of information. Although most of such information would not be burdensome to report, the data that would be required under §98.36(b)(5) would be burdensome for some units to report. That provision could require the reporting of calculated CO_2, CH_4, and N_2O data for each fuel type combusted at the unit. That would be a problem for units that use CEMS, since such methods generally do not employ instrumentation to record what type of fuel is being combusted at any point in time. AEP requests that EPA either delete §98.36(b)(5) or limit its application to units that already have the instrumentation or other means to calculate CO_2, CH_4, and N_2O emissions data by fuel type.

Response: EPA acknowledges the commenter's concerns, and has addressed this issue in the final rule. Section 98.36(b)(7) of the final rule states that, for Tier 4 units, the annual CO_2 emissions will be reported for all fuels combined, and that any biogenic CO_2 emissions will also be reported separately. It also states that CH_4 and N_2O emissions are to be reported for each type of fuel combusted, calculated in accordance with §98.33(c). In §98.33(c)(3), EPA has specified that reporters using Tier 4 are to use the best available estimates of the annual heat input from each type of fuel combusted in the unit during the reporting year, excluding fuel used only for startup or ignition. This can be from CEMS data or engineering calculations. Using this data they are to calculate CH_4 and N_2O emissions for each fuel type.

In revising the final version of the rule, EPA has also added §98.36(d) to define data reporting requirements for units subject to Part 75, which requires total emissions by unit, not by fuel. EPA believes that these provisions in the final rule effectively address the concerns of the commenters.

Commenter Name: [Name Not Given]
Commenter Affiliation: Graphic Arts Coalition (GAC)
Document Control Number: EPA-HQ-OAR-2008-0508-0701.1
Comment Excerpt Number: 11

Comment: Requiring submission after request within 7 days is unwarranted. EPA should provide a 30 day period in which to fulfill a data submission request. In addition, request for data submissions should only be made via hard copy.

Response: EPA acknowledges the commenter's concerns. In §98.36(e)(3) of the final rule, EPA has allowed owners or operators 30 days from receipt of a written request for information to respond to that request.

EPA does not believe that it is necessary to specify that requests for data submissions be made via hard copy mail. EPA believes that electronic requests are sufficiently reliable.

Commenter Name: Keith Overcash
Commenter Affiliation: North Carolina Division of Air Quality (NCDAQ)
Document Control Number: EPA-HQ-OAR-2008-0508-0588
Comment Excerpt Number: 11

Comment: Consistent with reporting for criteria and hazardous pollutants, reporting should be done at the unit/process level. We are concerned that 98.36(c), which permits aggregation of combustion units, will not allow separation of different combustion device types and different fuels. We support aggregation of small units if the device and fuel type are the same; if this is the intention of 98.36(c), then this should be clarified.

Response: EPA acknowledges the commenter's concerns and agrees that reporting in specific cases (identified in Subpart C) should be done at the unit level. However, EPA believes that the unit-level information that is reported in the case of aggregated units (i.e., unit ID numbers, maximum rated heat input capacity, etc.) is sufficient for the purposes of this rule because the aggregation provision applies to homogenous fuels and smaller units, which require less intensive data for verification under EPA's approach of linking data intensity to significance of the source. It is EPA's intention to allow the aggregation of any units with a maximum rated heat input capacity less than 250 mmBtu/hr, provided that the use of Tier 4 is not required or elected for any of the units, and that the units use the same Tier for any common fuels they combust. EPA believes that the unit aggregation provision as written in the final rule provides an appropriate balance between easing the burden on reporters and gathering useful data on GHG emissions.

Commenter Name: Marc J. Meteyer
Commenter Affiliation: Compressed Gas Association (CGA)
Document Control Number: EPA-HQ-OAR-2008-0508-0981.1
Comment Excerpt Number: 25

Comment: The proposed rule requires calculation and reporting of GHG emissions at the "unit-level" (unless the aggregation options of §98.36(c) are employed). Reporting emissions at the unit-level goes beyond the policy development intention of the reporting rule and increases the risk that confidential business information (operating rates, fuel choices, operating efficiencies) could be revealed in reports accessible to domestic and international competitors and customers of the regulated source. CGA Comment: Emission reporting should be required at the facility-level only by source type. Reporting at the unit-level should not be required. Additionally, provisions to protect the confidentiality of all process, production and business-related information required under the rule should be strengthened. While CGA accepts that facility-level emissions cannot be protected from public disclosure, it strongly requests all other information should, by default, be considered confidential business information and afforded the utmost protection from public disclosure.

Response: See the Preamble, Section II. R., and the response to comment EPA-HQ-OAR-2008-0508-0520.1 excerpt 16 for EPA's approach to CBI.

Also see the to the same comment, comment EPA-HQ-OAR-2008-0508-0520.1, excerpt 16 for the response to the need for unit-level data, including additional flexibility EPA has provided for aggregation and common pipe configurations at facilities.

Commenter Name: Renae Schmidt
Commenter Affiliation: CITGO Petroleum Corporation
Document Control Number: EPA-HQ-OAR-2008-0508-0726.1
Comment Excerpt Number: 14

Comment: For reasons stated earlier, CITGO disagrees with the reporting requirements of §98.36(b)(6) and §98.36(b)(9) for CH_4 and N_2O calculations from combustion sources. For paragraph §98.36(b)(6), the sentences appears to have left out Tier 3 calculation methodology (Tier 3 does not use Part 75 calculation methodology).

Response: EPA has substantially revised §98.36. The final rule addresses data reporting requirements for all Tiers.

See the Preamble, Section II. C., and the response to comment EPA-HQ-OAR-2008-0508-0561.1 excerpt 2 for information on the rationale for reporting for CH_4 and N_2O.

EPA believes that the use of fuel-specific emission factors for these pollutants strikes an appropriate balance between minimizing the burden on reporters and obtaining valuable GHG emission data. EPA has, however, revised the final rule to exclude CH_4 and N_2O emissions from fuels for which the rule does not provide emission factors, and has deleted the provision allowing the owner or operator of a facility to develop site-specific emission factors for such fuels. EPA believes that this change will reduce the reporting burden on facilities.

Commenter Name: See Table 6
Commenter Affiliation:
Document Control Number: EPA-HQ-OAR-2008-0508-0679.1
Comment Excerpt Number: 99

Comment: Page 16631/Sec 98.32: Stationary combustion units are required to report at the unit level. Reporting at the unit level is overly burdensome. In Section 98.36(c)(3) on Page 16637, aggregation of small units is permitted; however, some sites have no metering. API requests the use of small unit aggregation methods based on parameters such as design capacity, hours of operation, load, and fuel characteristics.

Response: See the response to comment EPA-HQ-OAR-2008-0508-0520.1 excerpt 16 for the response to the need for unit-level data, including additional flexibility EPA has provided for aggregation and common pipe configurations at facilities.

Commenter Name: Renae Schmidt
Commenter Affiliation: CITGO Petroleum Corporation
Document Control Number: EPA-HQ-OAR-2008-0508-0726.1
Comment Excerpt Number: 16

Comment: CITGO disagrees that the following information should be reported (but rather maintained in the records): Tier 2 Calculation Methodology (§98.36(dXii): (B) Monthly high heat values used in the equations (0) Indication of actual or substituted value Tier 3 Calculation Methodology (§98.36(dXiii): (B) Number of required carbon content determinations for each fuel (C) Each carbon content value used (D) Indication of actual or substituted value (E) Dates and results of calibrations - should only report exceptions (H) Methods used to determine carbon content (I) Methods used to calibrate fuel flow meters These types of records are suitable for calculation tools such as process historians, database systems, and spreadsheet calculations. Transfer of this information into another (and currently unknown) electronic report system is completely unnecessary to achieve intended reporting rule objectives. At our largest refinery, there are over 50 heaters and boilers with nearly 100 fuel gas meters. Reporting all of the above information is completely unnecessary. Reporting should focus on the core emission data, source identification, and exceptions to any requirements.

Response: See the response to comment EPA-HQ-OAR-2008-0508-0520.1 excerpt 16 for the response to the need for unit-level data, including additional flexibility EPA has provided for aggregation and common pipe configurations at facilities.

EPA has made a number of significant adjustments in the final rule to the data reporting requirements of §98.36, both to clarify those requirements and to reduce the reporting burden. EPA is allowing facilities to keep more records on-site, and submit them within 30 days of a written request from the Administrator or from the applicable state or local air pollution control agency (see §98.36(e)(3).)

The final rule retains the requirement to report monthly HHV values and to use flags to indicate whether each is an actual, measured value or is substitute data. However, the proposed Tier 3 requirement to report all carbon content and molecular weight values has been relaxed. Only monthly average values of these parameters are required to be reported. Further, the final rule requires only that records be kept of the CEMS and fuel flow meter QA tests and the methods used. The test results are not required to be reported electronically or in hard copy, but must be made available to EPA and/or the State agencies upon request.

Commenter Name: Caroline Choi
Commenter Affiliation: Progress Energy
Document Control Number: EPA-HQ-OAR-2008-0508-0439.1
Comment Excerpt Number: 16

Comment: Under 98.36(b), EPA proposes to require unit level reporting of various pieces of information not only for Subpart C combustion sources, but also for ARP units. Although most of the information specified in 98.36(b) is not burdensome to report, the data required under (b)(5) would be for some units. Proposed 98.36(b)(5) would require the reporting of calculated CO_2, CH_4, and N_2O data, for each fuel type combusted at the unit. Units using continuous monitoring methods, like CO_2/O_2 CEMS and volumetric flow monitors (to calculate heat input) generally do not employ instrumentation to record when a different fuel is being combusted. For example, a coal-fired unit that uses oil to startup would monitor CO_2/O_2 and volumetric flow all the way through the startup process and past the point when coal enters the boiler without recordation of when the change in fuel took place. Similarly, some oil and gas-fired units may switch between the two fuels, or even co-fire oil and gas, without recording which fuel type was responsible for the emissions and flow. For such units, it is not possible to provide estimates of emissions by fuel type without addition of what might he complicated, expensive, and otherwise unnecessary instrumentation. Therefore, Progress Energy urges EPA to remove the provision from the rule.

Response: EPA acknowledges the commenter's concerns, and has addressed this issue in the final rule. Section 98.36(b)(7) of the final rule states that, for Tier 4 units, the annual CO_2 emissions will be reported for all fuels combined, and that any biogenic CO_2 emissions will also be reported separately. It also states that CH_4 and N_2O emissions are to be reported for each type of fuel combusted, calculated in accordance with §98.33(c). In §98.33(c)(3), EPA has specified that reporters using Tier 4 are to use the best available estimates of the annual heat input from each type of fuel combusted in the unit during the reporting year, excluding fuel used only for startup or ignition. This can be from CEMS data or engineering calculations. Using this data they are to calculate CH_4 and N_2O emissions for each fuel type.

In revising the final version of the rule, EPA has also added §98.36(d) to define data reporting requirements for units subject to Part 75, which requires total emissions by unit, not by fuel. EPA believes that these provisions in the final rule effectively address the concerns of the commenters.

Commenter Name: Kyle Pitsor
Commenter Affiliation: National Electrical Manufacturers Association (NEMA)
Document Control Number: EPA-HQ-OAR-2008-0508-0621.1
Comment Excerpt Number: 21

Comment: The NEMA Carbon/Manufactured Graphite EHS Committee agrees with the EPA's proposal under §98.36(c)(1) and (c)(3), to allow a facility to aggregate combustion units for the purpose of simplifying its calculations for estimating GHG emissions. According to this proposed language, a facility can 1) aggregate smaller combustion units into "process-level" groups, as long as the combined maximum rated heat input capacity is < 250 mmBtu/hr per group and provided the amount of fuel use can be accurately quantified, or 2) combine units supplied by a common fuel supply piping configuration if there is a calibrated fuel flow meter, with no restriction on the total maximum rated heat input capacity of the group. In fact, the NEMA Carbon/Manufactured Graphite EHS Committee believes that aggregating smaller combustion units into "process-level" groups should also not be limited to groups having combined maximum rated heat input capacity is < 250 mmBtu/hr, provided the facility has sufficient monitoring/metering systems to accurately quantify the amount of fuel used. While this maximum rated heat input capacity may be consistent with the definition of a large unit under other regulatory programs, this added limitation in this case will not improve the quality of GHG emissions data, but may cause a facility the unnecessary burden to add or upgrade current fuel metering systems. This flexibility will allow each facility to monitor fuel use, collect data and calculate emissions in the most efficient way for its operations, without negatively affecting the accuracy or consistency of the submitted emissions data, and without unnecessary added costs of installing or upgrading fuel metering systems. However, this flexibility will be wholly negated if the facility has to install CEMS simply because a combustion unit exceeds 1,000 hours of operations.

Response: EPA appreciates the commenter's support, and has made a number of significant adjustments in the final rule to the data reporting requirements of §98.36, both to clarify those requirements and to reduce the reporting burden. For units that use Tiers 1, 2, and 3 to calculate CO_2 mass emissions, the cumulative 250 mmBtu/hr heat input capacity limit on the aggregation of units into a group has been dropped. Rather, the 250 mmBtu/hr restriction applies only to the individual units in the group. Therefore, for reporting purposes, individual units with maximum rated heat input capacities of 250 mmBtu/hr or less may be aggregated without limit into a single group, provided that the Tier 4 methodology is not required for any of the units, and all units in the group use the same tier for any common fuel(s) that they combust. Units with maximum rated heat inputs greater than 250 mmBtu/hr must report as individual units, unless they burn the same type of fuel (oil or gas) provided by a common pipe or supply line; in that case, the owner or operator may opt to use the highest tier required for a grouped unit for the calculation method with the common pipe reporting provisions in §98.36(c)(3). Units using Tier 4 must report as individual units unless they share a monitored common stack; in that case, the common stack reporting provisions of §98.36(c)(2) may be used.

Additionally, a facility is required to install CEMS only if each of the criteria under §98.33(b)(4)(ii) are met.

Commenter Name: Kathy G. Beckett
Commenter Affiliation: West Virginia Chamber of Commerce
Document Control Number: EPA-HQ-OAR-2008-0508-0956.1
Comment Excerpt Number: 21

Comment: Under §98.36(b), EPA proposes to require unit level reporting of various pieces of information not only for Subpart C combustion sources, but also for ARP units. See Proposed §98.46(a). Although most of the information specified in §98.36(b) is not burdensome to report, the data required under (b)(5) would be for some units. Proposed §98.36(b)(5) would require the reporting of calculated CO_2, CH_4, and N_2O data for each fuel type combusted at the unit. Units using continuous monitoring methods, like CO_2/O_2 CEMS and volumetric flow monitors (to calculate heat input) generally do not employ instrumentation to record when a different fuel is being combusted. For such units, it simply is not possible to provide estimates of emissions by fuel type without addition of what might be complicated, expensive, and otherwise unnecessary instrumentation. It is not obvious why such data are needed to fulfill Congress' mandate. EPA should remove the provision or limit its application to units that already have the instrumentation or other means to make the calculation. If EPA retains the requirement, EPA must describe why the information is needed, estimate the costs of gathering this information, and provide sufficient time for installation of equipment.

Response: EPA acknowledges the commenter's concerns, and has addressed this issue in the final rule. Section 98.36(b)(7) of the final rule states that, for Tier 4 units, the annual CO_2 emissions will be reported for all fuels combined, and that any biogenic CO_2 emissions will also be reported separately. It also states that CH_4 and N_2O emissions are to be reported for each type of fuel combusted, calculated in accordance with §98.33(c). In §98.33(c)(3), EPA has specified that reporters using Tier 4 are to use the best available estimates of the annual heat input from each type of fuel combusted in the unit during the reporting year, excluding fuel used only for startup or ignition. This can be from CEMS data or engineering calculations. Using this data they are to calculate CH_4 and N_2O emissions for each fuel type.

In revising the final version of the rule, EPA has also added §98.36(d) to define data reporting requirements for units subject to Part 75, which requires total emissions by unit, not by fuel. EPA believes that these provisions in the final rule effectively address the concerns of the commenters.

See the Regulatory Impact Analysis (RIA) for a detailed description of EPA's cost estimates for reporting under Subpart C.

Commenter Name: Patrick J. Nugent
Commenter Affiliation: Texas Pipeline Association (TPA)
Document Control Number: EPA-HQ-OAR-2008-0508-0460.1
Comment Excerpt Number: 22

Comment: TPA supports proposed §98.36(c), which would allow the use of specified reporting alternatives for stationary combustion units in certain circumstances. This proposed rule takes a measured approach to EPA's data collection efforts that minimizes unnecessary burden on the regulated community.

Response: EPA appreciates the commenter's support, and has made a number of significant adjustments in the final rule to the data reporting requirements of §98.36, both to clarify those requirements and to reduce the reporting burden. For units that use Tiers 1, 2, and 3 to calculate CO_2 mass emissions, the cumulative 250 mmBtu/hr heat input capacity limit on the aggregation of units into a group has been dropped. Rather, the 250 mmBtu/hr restriction applies only to the individual units in the group. Therefore, for reporting purposes, individual units with maximum rated heat input capacities of 250 mmBtu/hr or less may be aggregated without limit into a single group, provided that the Tier 4 methodology is not required for any of the units, and all units in the group use the same tier for any common fuel(s) that they combust. Units with maximum rated heat inputs greater than 250 mmBtu/hr must report as individual units, unless they burn the same type of fuel (oil or gas) provided by a common pipe or supply line; in that case, the owner or operator may opt to use the highest tier required for a grouped unit for the calculation method with the common pipe reporting provisions in §98.36(c)(3). Units using Tier 4 must report as individual units unless they share a monitored common stack; in that case, the common stack reporting provisions of §98.36(c)(2) may be used.

Commenter Name: Kyle Pitsor
Commenter Affiliation: National Electrical Manufacturers Association (NEMA)
Document Control Number: EPA-HQ-OAR-2008-0508-0621.1
Comment Excerpt Number: 22

Comment: The NEMA Carbon/Manufactured Graphite EHS Committee believes it is commonplace for a reporting facility to have multiple combustion units supplied by a common fuel supply piping configuration, where the primary, or in many cases the only, fuel flow meter is the billing meter owned and operated by the fuel supplier. In this case, the NEMA Carbon/Manufactured Graphite EHS Committee believes that the supplier, rather than the combustion facility, should be responsible under this GHG reporting rule for meeting calibration and all the other requirements associated with maintaining this fuel use monitoring system in good operating order and retaining the required recordkeeping for documentation purposes. The amount of fuel used, in this case, should be quantified through the use of purchase receipts or similar billing records provided to the facility by the fuel supplier. Since the supplier's metering system is used for billing purposes, it would be expected to be properly maintained so as to provide accurate measurements of the facility's fuel use. As nearly all GHG reporting facilities will have such fuel purchase records from the supplier, this will be the most efficient and least burdensome method for facilities to obtain fuel usage data.

Response: EPA acknowledges the concerns of the commenters. Section 98.34(b)(1)(iii) of the final rule provides that fuel billing meters are exempted from the calibration requirement, "provided that the supplier and the unit(s) combusting the fuel do not have any common owners and are not owned by subsidiaries or affiliates of the same company." Further, for Tiers 1 and 2, the "company records" (see §98.6) used to quantify fuel usage include data from qualifying gas billing meters. The nomenclature under Equations C-4 and C-5 in §98.33 also provide that data from qualifying fuel billing meters may be used to determine fuel usage for the Tier 3 calculation methodology.

Commenter Name: Kimberly S. Lagomarsino
Commenter Affiliation: Mississippi Lime
Document Control Number: EPA-HQ-OAR-2008-0508-1568
Comment Excerpt Number: 22

Comment: 40 CFR 98.36 requires "the annual GHG emissions report shall contain the unit-level or process-level emissions data..." as well as the "maximum rated heat input capacity of the unit...." Such rated heat input capacity information, on a unit-level, is highly sensitive and confidential business information. And, as previously noted, Mississippi Lime Company is unable to determine exact process emissions on a kiln-by-kiln basis. Suggestion: Please revise 98.36 to allow for the facility-level reporting of emissions. In addition, please indicate that unit-level information, as much as is available, must be retained on-site and must be available for review upon request.

Response: See the Preamble, Section II. R., and the response to comment EPA-HQ-OAR-2008-0508-0520.1 excerpt 16 for EPA's response on CBI. Also see the response to the same comment, comment EPA-HQ-OAR-2008-0508-0520.1, excerpt 16 for the response to the need for unit-level data, including additional flexibility EPA has provided for aggregation and common pipe configurations at facilities. The response to this cited comment also indicates how this additional flexibility may be useful for the Lime industry.

EPA has decided to retain the requirement to report the maximum rated heat input capacity of each unit for boilers, combustion turbines, engines, and process heaters. EPA believes that the definition of "maximum rated heat input capacity" in §98.6 clarifies that this term refers to "the hourly heat input to a unit (in mmBtu/hr), when it combusts the maximum amount of fuel per hour that it is capable of combusting on a steady state basis, as of the initial installation of the unit, as specified by the manufacturer."

Commenter Name: See Table 3
Commenter Affiliation:
Document Control Number: EPA-HQ-OAR-2008-0508-0433.2
Comment Excerpt Number: 23

Comment: The data reporting requirements of §98.36 will also require data processing updates for many facilities with existing CEMs installations. These may arise from the need to capture new information not already included in emission reports, adding calculations to compute pollutant averages in the individual units as specified by the rule, or calculating emissions of GHG emissions not directly measured by the facility. Furthermore, since the specific data reporting requirements are not specified in the draft rule, but "will be provided" by the EPA, additional facility resources will be required to implement the reporting requirements when they are finalized. If release and implementation of the EPA-mandated reporting is at all like that of 40 CFR parts 75, these resources may be substantial. The lack of a predefined data reporting format in the proposed rule should be addressed and subjected to public comment prior to publication of any Final rule arising from this proposal.

Response: See the Preamble and separate comment response document for the response on collection, management, and dissemination of GHG emissions data.

The data reporting format for Part 98 is currently under development by EPA. The exact format will be presented to the public as soon as possible, to allow time for the regulated sources to become familiar with it. The Agency will base the reporting format on the data elements that are required to be reported under the various Subparts of the rule.

Commenter Name: Sarah B. King
Commenter Affiliation: DuPont Company
Document Control Number: EPA-HQ-OAR-2008-0508-0604.1
Comment Excerpt Number: 12

Comment: EPA should recognize the reality that the most accurate and verifiable determination of energy consumption based CO_2 emissions would result from applying emission factors to sitewide fuel consumption, purchased electricity consumption, purchased steam consumption, etc. The consumption of fuels, electricity and other energy-bearing materials (e.g., steam) is easily verifiable using third-party invoices. This method in many cases provides a complete and comprehensive accounting of sitewide combustion-based CO_2 emissions. Requirements to report emissions at the combustion unit level do not improve the accounting of GHG emissions; rather, they are likely to impose significant inaccuracies while substantially increasing the burden in terms of investment in monitoring devices, costs of calibration and maintenance, development and maintenance of data management systems, recordkeeping and personnel time commitments. Inaccuracies occur due to flow meter errors, CEMS errors, unmonitored fugitive errors and the multiplication of all these errors over dozens or hundreds of devices at a complex facility. Rather than requiring the complex and costly methodologies for inherently less accurate unit-based reporting of GHG emissions, EPA should emphasize the need to provide accurate sitewide energy consumption-based GHG emissions reporting and allow a reasonable estimation basis for distributing fuel, electricity and other energy-bearing materials – and their respective GHG emissions – among combustion units and other operations. Reasonable estimations could be made based on internal site fuel and electricity metering, process knowledge, and other reasonable methods. The key point is that the sitewide GHG emission values would be accurate and verifiable so that the national inventory of emissions would be accurate.

Response: See the Preamble, Section II. L., on General Monitoring Requirements for the overall rationale for methodologies required under this rule, and the response to comment EPA-HQ-OAR-2008-0508-0909.1 excerpt 4 and EPA-HQ-OAR-2008-0508-0580 excerpt 10 for the rationale for methodologies required under Subpart C.

See the Preamble, Section II. D, for the selection of source categories to report.

Though EPA disagrees with the commenter's proposed monitoring approach, EPA has made a number of significant adjustments in the final rule to the data reporting requirements of §98.36, both to clarify those requirements and to reduce the reporting burden. For units that use Tiers 1, 2, and 3 to calculate CO_2 mass emissions, the cumulative 250 mmBtu/hr heat input capacity limit on the aggregation of units into a group has been dropped. Rather, the 250 mmBtu/hr restriction applies only to the individual units in the group. Therefore, for reporting purposes, individual units with maximum rated heat input capacities of 250 mmBtu/hr or less may be aggregated without limit into a single group, provided that the Tier 4 methodology is not required for any of the units, and all units in the group use the same Tier for any common fuel(s) that they combust. Units with maximum rated heat inputs greater than 250 mmBtu/hr using Tiers 1, 2, and 3 must report as individual units, unless they burn the same type of fuel provided by a common pipe or supply line; in that case, the owner or operator may opt to use the highest Tier required for a grouped unit for the calculation method with the common pipe reporting provisions in §98.36(c)(3). Units using Tier 4 must report as individual units unless they share a monitored common stack; in that case, the common stack reporting provisions of §98.36(c)(2) may be used.

Commenter Name: Robert D. Bessette
Commenter Affiliation: The Council of Industrial Boiler Owners (CIBO).
Document Control Number: EPA-HQ-OAR-2008-0508-0513.1
Comment Excerpt Number: 38

Comment: Regarding, §98.36(c)(1), aggregation is unduly limited in applicability by imposing an aggregate maximum heat input capacity of 250 MMBtu/hr. There should be no aggregate limit if a common fuel is used and the analytic data to determine total emissions is representative of all units in the identified group. Imposing a limit of 250 MMBtu/hr is arbitrary and there is no legal or policy rationale to justify imposing these additional compliance costs.

Response: EPA acknowledges the concerns of the commenter. EPA has made a number of significant adjustments in the final rule to the data reporting requirements of §98.36, both to clarify those requirements and to reduce the reporting burden. For units that use Tiers 1, 2, and 3 to calculate CO_2 mass emissions, the cumulative 250 mmBtu/hr heat input capacity limit on the aggregation of units into a group has been dropped. Rather, the 250 mmBtu/hr restriction applies only to the individual units in the group. Therefore, for reporting purposes, individual units with maximum rated heat input capacities of 250 mmBtu/hr or less may be aggregated without limit into a single group, provided that the Tier 4 methodology is not required for any of the units, and all units in the group use the same tier for any common fuel(s) that they combust.

Commenter Name: See Table 4
Commenter Affiliation:
Document Control Number: EPA-HQ-OAR-2008-0508-0455.1
Comment Excerpt Number: 19

Comment: However, the Class of '85 urges EPA to reconsider its proposed verification response period. As proposed, the rule allows only a seven-day verification response period. The Class of '85 does not believe that, given the potential breadth of the data request contemplated by this part, the proposed response period is appropriate or reasonable. Therefore, the Group urges EPA to lengthen this response period to 30 days.

Response: EPA acknowledges the commenter's concerns. In the final rule, EPA has allowed owners or operators 30 days from receipt of a written request for verification information to respond to that request.

Commenter Name: Lorraine Krupa Gershman
Commenter Affiliation: American Chemistry Council (ACC)
Document Control Number: EPA-HQ-OAR-2008-0508-0423.2
Comment Excerpt Number: 6

Comment: EPA should allow facilities more time to respond for data requests. Requiring a response to a written request within seven days is an impossible deadline. A person might be on vacation, and might not even see the request in that time period. While the records likely will be readily available, it will take a bit of time to compile them and send them. Further, the timing to produce the records may be in conflict with other legally required reporting obligations and result in missing the deadline. EPA should allow a minimum of 30 days to fulfill a data submission request, with an option for an extension if the facility requests it and explains why an extension is needed. We are concerned about EPA's proposal to request data through an electronic mailing to the facility. We believe it is important for EPA to request any data through a hard copy mailing, with an additional electronic request if desired. Our concern is that facility personnel and email addresses change over time, and it is very likely that a response sent only by email would not be received in a timely manner. Further, with the proliferation of SPAM and unwanted email, it is important that a facility be able to determine when it is in receipt of a legitimate data request.

Response: EPA acknowledges the commenter's concerns. In the final rule, EPA has allowed owners or operators 30 days from receipt of a written request for information to respond to that request.

9. RECORDS THAT MUST BE RETAINED

Commenter Name: Lauren E. Freeman
Commenter Affiliation: Hunton & Williams LLP
Document Control Number: EPA-HQ-OAR-2008-0508-0493.1
Comment Excerpt Number: 37

Comment: EPA uses proposed §98.37 to restate which records must be kept under other provisions of Subparts A and C, and to state which provisions require "no special recordkeeping." This provision is unnecessary and confusing. If the recordkeeping requirements in the other provisions are clearly stated, there is no need to repeat them in a separate provision. If EPA wishes to highlight the fact that proposed §98.34(a) and (b) and §98.35(b)(2) include recordkeeping requirements, that could be accomplished by including the word "recordkeeping" in the section titles. UARG also notes that proposed §98.37 includes references to several subsections that do not exist in the proposed Subpart -- i.e., §98.35(a)(1), 98.35(a)(4). To the extent this provision is intended to require retention of records created under Part 75 for more than 3 years, UARG also objects to it for the reasons stated above in comments on Subpart A.

Response: EPA believes that the provisions of the revised §98.37 are appropriate and necessary. The commenter should note that §98.37 no longer refers to §98.35(a)(1) or §98.35(a)(4).

10. COST DATA

Commenter Name: See Table 10
Commenter Affiliation:
Document Control Number: EPA-HQ-OAR-2008-0508-0635
Comment Excerpt Number: 20

Comment: CEMS are cost-effective. In most, if not all, of these cases, CO_2 CEMS, at the least, are available for one hundred thousand dollars or less – which is generally a very small percentage of the total cost of a new facility. [Footnote: 142 Cf. EPA, EPA Air Pollution Costs Manual (2002), available at: http://www.epa.gov/ttn/catc/dir1/c_allchs.pdf.][142] CEMS for other gases are not substantially more expensive, and the price would certainly drop if the market for these CEMS grew. Moreover, the overall societal value of a functioning carbon market will far outweigh monitoring costs. Good data will create value here, just as it has in the Acid Rain Program context, where the benefits of a well-functioning market have outweighed CEMS and other system costs forty times over. [footnote: [143] See Lorraine G. Chestnut & David M. Mills, A Fresh Look at the Benefits and Costs of the U.S. Acid Rain Program, 77 J. of Environ. Mgmt. 252, 266 (2005) (Ex. 18).]

Response: EPA agrees with the commenter that in many cases, CEMS are an appropriate means to monitor CO_2 emissions. EPA has retained the requirement for units meeting all the conditions in §98.33(b) to use CO_2 or O_2 CEMS to monitor their CO_2 emissions. Units that are already required to monitor and report CO_2 under Part 75 will also continue to do so under Part 98. However, EPA does not believe that it is appropriate to require all stationary combustion units to install CO_2 CEMS at this time, as this would be overly burdensome to regulated sources in the context of a data-gathering program, regardless of potential future regulatory efforts. Additionally, EPA is not implementing or planning to implement a cap and trade program for GHGs at this time and is therefore has not designed this reporting rule specifically to support a cap and trade program.

Commenter Name: Rhea Hale
Commenter Affiliation: American Forest & Paper Association (AF&PA)
Document Control Number: EPA-HQ-OAR-2008-0508-0909.1
Comment Excerpt Number: 10

Comment: AF&PA is concerned that the cost to the industry for Tier 4 methodology is inconsistent with the stated goal of the proposed rule to minimize the burden on the industry. The pulp and paper industry has over 105 boilers with fuel capacity greater than 250 MMBtu/hr that burn coal as a primary or secondary fuel, of which a large portion have CEMs already installed. The estimated cost to add CO_2 analyzers to these units ranges from $15,000 per unit to $75,000 per unit depending on type of sample system, any necessary reconfiguration of the system, and the potential addition of calibrated fuel flow meters or stack fuel gas flow monitors. An estimated 75 boilers would require an additional $45,000 per unit in upfront costs which could total $3.4 million dollars. This cost is unreasonable, particularly given the industry's propensity to co-fired biomass which requires the use of emissions factors to calculate emissions despite the existence of CEMS. These costs do not include the additional maintenance requirements and quality assurance costs that would be associated with additional CEMs.

Response: EPA is requiring the use of CEMS for solid fossil fuel-fired units due to the complexity of monitoring solid fuel consumption and the heterogeneous nature of the solid fuels. EPA has considered the commenter's analysis, but disagrees with the commenter's assessment of the level of burden associated with installing and maintaining the concentration and volume monitors that the rule requires be added to an existing CEMS. In the revised rule, EPA has clarified that if the unit in question meets all six criteria then a CO_2 or O_2 and a stack gas volumetric flow rate monitor would be required to be installed. EPA's cost estimates are annualized and fall within the range of capital costs cited in this comment. Further detail on the engineering cost analysis for Subpart C can be found in RIA (EPA-HQ-OAR-2008-0318-002), Section 4.3.

Commenter Name: Dale Backlund, Regulatory Affairs Leader, The DOW Chemical Company and Victoria Evans, National Practice Leader for Greenhouse Gases, URS Corporation
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2008-0508-1338
Comment Excerpt Number: 4

Comment: Downscaling to reporting GHG emissions at the facility level is especially burdensome for General Stationary Combustion sources for data Tiers 3 and 4. These require individual monitoring on either monthly (Tier 3) or continuous (Tier 4) bases, for both the flow and the fuel content. Additional costs for purchasing, installing, calibrating, maintaining, recalibrating, and certifying these monitors, meters, and sensors on individual sources is anticipated (see below). Since the greenhouse gas issue is on a tens of tons or hundreds of tons basis, the cost of doing daily feed analysis or adding CEMS to the combustion device is not warranted.

Response: EPA has considered this comment but has retained the rule language from the proposed rule requiring that emissions be reported at the facility level. In preparation of the final rule, EPA has loosened the unit aggregation requirements for reporting, lifting the 250 mmBtu/hr total heat input limit on the aggregation of units into groups for reporting purposes.

EPA has clarified its general monitoring approach in the final rule. While EPA intends that facilities that meet all of the conditions in §98.33(b) to use Tier 4 methods, EPA does not intend that CEMS be added in order to comply with this rule. EPA does require facilities with CEMS to add CO_2 or O_2 concentration monitors if necessary in order to determine emissions.

In preparation of the final rule, EPA has revised the mandatory fuel sampling and analysis requirements for traditional fossil fuels for Tiers 2 and 3 and has revised §98.34 to require that natural gas be sampled semiannually, and that a representative sampling be taken from each fuel shipment or delivery for fuel oil and coal. For other liquid fuels and biogas, quarterly sampling is required. For other solid fuels, excluding municipal solid waste, weekly composite sampling with monthly analysis is required. For other gaseous fuels, the daily sampling requirement has been retained, but only for facilities with existing equipment in place that is capable of providing the data. Otherwise, weekly sampling is required.

Commenter Name: Craig S. Campbell
Commenter Affiliation: Lafarge North America
Document Control Number: EPA-HQ-OAR-2008-0508-0674.1
Comment Excerpt Number: 4

Comment: EPA maintains that adding CO_2 CEMs will be cost effective for facilities that already have other continuous monitors in place. At 74 Fed. Reg. 16483 EPA states: The incremental cost of adding a diluent gas (CO_2 or O_2) monitor or a flow monitor, or both, to meet Tier 4 monitoring requirements would likely not be unduly burdensome for a large unit that combusts solid fossil fuels or MSW, operated frequently, and is already required to install, certify, maintain, and operate CEMS and to perform on-going QA testing of the existing monitors. The cost of compliance with the proposed rule would be even less for units that already have all of the necessary monitors in place. Lafarge's research on CO_2 CEMs indicates that in many cases the retrofit installation for these units will present technology-compatibility challenges (with respect to the existing installed monitoring systems), and higher costs than used in EPA's economic impact analysis. In our current assessment it appears an FTIR hot/wet system is best suited for monitoring CO_2 emissions from cement kilns. These units can measure within the desired range (25 to 35% CO_2) and offer good accuracy. However, this technology is not easily adapted to the existing CEMs systems in-place at of our most cement plants. Retrofitting an existing CEMs unit with a stand alone CO_2 analyzer is also problematic – in some cases the sampling system cannot accommodate another analyzer, in other cases the facility would essentially be forced to use an older technology that is less accurate and perhaps less reliable. Lafarge's preliminary engineering cost estimate for installing new CO_2 CEMs at its existing plants is approximately $175,000 per kiln, with an annual operating cost of approximately $25,000 per kiln (Lafarge operates 22 cement kilns in the U.S., ranging from 1 to 5 kilns per plant). Lafarge's installation cost estimate is more than 3 times higher than the "fist cost" installation cost estimates used in EPA's Economic Impact analysis. But even more importantly, any additional costs for a new/duplicative monitoring system would be unwarranted given the already well-established WBCSD Cement CO_2 protocol.

Response: See the response to comment EPA-HQ-OAR-2008-0508-0455.1 excerpt 7 and the response to comment EPA-HQ-OAR-2008-0508-0580 excerpt 10 for EPA's rationale and approach to the use of CEMS.

EPA is requiring the use of CEMS for solid fossil fuel-fired units with installed CEMS that are required by applicable Federal or State regulation or the unit's operating permit due to the complexity of monitoring solid fuel consumption and the heterogeneous nature of the solid fuels. EPA has considered the commenter's analysis, but disagrees with the commenter's assessment of the burden associated with installing and maintaining the concentration and volume monitors that the rule requires be added to an existing CEMS. In the revised rule, EPA has clarified that if the unit in question meets all six criteria then a CO_2 or O_2 and a stack gas volumetric flow rate monitor would be required to be installed. EPA's estimates of monitoring costs are averages for a representative facility and may not represent the actual cost in individual circumstances.

Commenter Name: Rich Raiders
Commenter Affiliation: Arkema Inc.
Document Control Number: EPA-HQ-OAR-2008-0508-0511.1
Comment Excerpt Number: 44

Comment: EPA underestimated Subpart C compliance costs for reporting facilities. Table 4.2h of the Regulatory Impact Analysis for the Mandatory Reporting of Greenhouse Gas Emissions Proposed Rule, Final Report, EPA, March 2009 ("RIA") indicates that setup costs for in-stack gas sampling can be completed for $3,270. Simple Arkema stack test programs, not including any MACT-related testing protocols, cost $10,000 to plan and execute one time. Very little of these prior protocols is recoverable for subsequent sampling events, so most of the $10,000 cost is incurred every time a sample is required. EPA should double the annual cost estimate for fuel sampling and eliminate the fuel sampling requirement for commodity fuel consumers. EPA does not include instrumentation costs for automated gas sampling equipment when safety considerations prohibit reporters from testing or obtaining grab samples of some fuel streams. Arkema estimated that inline process equipment capable of managing Tier 3 data collection requirements would cost approximately $250,000 each to install and $20,000 per year to operate. Requiring 15 such meters to manage potential Arkema Tier 3 streams, Arkema would invest $3.75 million in monitoring potential Tier 3 streams. EPA did not include the cost of replacing gas flow meters for Subpart C compliance. Many existing natural gas and diesel fuel flow meters are not capable of calibration, may have never been calibrated, or may only be calibrated by pipeline personnel. EPA should either remove the calibration requirement in lieu of reliance on vendor sales records or include in their cost estimate replacement natural gas meters. EPA should not require or encourage commodity fuel meter replacement under any Subpart C final regulation.

Response: Concerning sampling, in preparation of the final rule, EPA has revised the mandatory fuel sampling and analysis requirements for traditional fossil fuels for Tiers 2 and 3 and has revised §98.34 to require that natural gas be sampled semiannually, and that a representative sampling be taken from each fuel shipment or delivery for fuel oil and coal. For other liquid fuels and biogas, quarterly sampling is required. For other solid fuels, excluding municipal solid waste, weekly composite sampling with monthly analysis is required. For other gaseous fuels, the daily sampling requirement has been retained, but only for facilities with existing equipment in place that is capable of providing the data. Otherwise, weekly sampling is required.

EPA further notes that the applicability of Tier 3 was revised, and the requirements are now only applicable to large units (i.e., > 250 mmBtu) for fuels either included in Table C-1 or that contribute greater than ten percent of the heat input to a unit. Concerning calibration, EPA acknowledges the concerns of the commenters. Section 98.34 of the final rule has been clarified to allow calibration procedures specified by the flow meter manufacturer or an industry-accepted or industry consensus standard calibration method. Section 98.34 also exempts fuel billing meters from the calibration requirement, "provided that the supplier and the unit(s) combusting the fuel do not have any common owners and are not owned by subsidiaries or affiliates of the same company." EPA also recognizes that for many continuous industrial processes such as petroleum refineries, removal of a flow meter for calibration could be severely disruptive of normal process operation. In view of this, today's rule allows these facilities to perform the initial flow meter calibrations and subsequent recalibrations for orifice, nozzle, or venturi meters at the time of scheduled maintenance outages.

Keeping in mind this additional flexibility on calibration, it is noted that EPA's estimates of monitoring costs are averages for a representative facility and may not represent the actual cost in individual circumstances.

Commenter Name: Sam Chamberlain
Commenter Affiliation: Murphy Oil Corporation
Document Control Number: EPA-HQ-OAR-2008-0508-0625
Comment Excerpt Number: 32

Comment: Report on CO_2, CH_4, and N_2O. See Subpart C, Table C-1 for additional guidelines. Includes boilers, combustion turbines, engines, incinerators, process heaters, etc... For ≥ 250 mm BTU/hr Nat Gas (liquid & gaseous fossil fuel) requires Tier 3 methodology. Tier 3 = periodic (Monthly) determination of carbon content of fuel and DIRECT measurement of fuel combusted. Daily determinations of refinery gas, process gas also required if used as a fuel. EPA says online chromatographs are likely in place. Tank drop measurements can be used for fuel oil. Murphy has analyzed its refineries and have determined significant regulatory burden and we have no online chromatographs in operation. At one refinery only the #2 FCC, Crude heater and Platformer Charge and Hydrocracker combined heaters fall under Tier 4 reporting. All other fired sources fall under Tier 3 and use installed fuel flow measurement and sampling. However, QA/QC requirements will have to be improved to meet the EPA QAPP criteria. In addition, many orifice plate, pressure transducers flow meters will need to be upgraded or replaced. Pilot gas flow measurement and fuel gas samples will be problematic for meeting proposed rules. Murphy may be required to install additional CEMS, hire additional laboratory personnel and/or purchase additional sampling equipment. Murphy has estimated the cost of compliance to meet the stationary combustion sources to approach close to $1,000,000, which includes and not limited to purchase of three CEMS, additional laboratory sampling equipment, additional manpower resources, etc. And these compliance requirements cannot be installed on or before January 1, 2010, therefore Murphy recommends submitting best professional judgment for the first reporting period of GHG emissions for 2010.

Response: See the Preamble, Section III. C., for EPA's response on the method for calculating GHG emissions. Please see the Preamble, Section III. G., "Summary of Comments and Responses on Initial Reporting Year and Best Available Monitoring Methods," for information on additional flexibility for 2010.

EPA is requiring the use of CEMS for solid fossil fuel-fired units with installed CEMS that are required by applicable Federal or State regulation or the unit's operating permit due to the complexity of monitoring solid fuel consumption and the heterogeneous nature of the solid fuels. EPA's estimates of monitoring costs are averages for a representative facility and may not represent the actual cost in individual circumstances.

The final rule requires data collection for calendar year 2010, but has been changed since proposal to allow use of best available monitoring methods for the first part of 2010. In addition, EPA has added additional flexibility to its fuel flow meter calibration requirements (see §98.3(i)).

Commenter Name: See Table 3
Commenter Affiliation:
Document Control Number: EPA-HQ-OAR-2008-0508-0433.2
Comment Excerpt Number: 21

Comment: The total capital and installation costs for installation of a CO_2 analyzer to an existing combustion source can range from perhaps as low as $25,000 in a best-case situation, up to as much as $500,000 for a major facility upgrade. Once a CO_2 monitor is added to the CEMS or an existing CO_2 or O_2 monitor installed only to provide process control data becomes subject to the proposed 40 CFR part 98 requirements, the quality assurance requirements of this rule will add substantial additional annual operating costs to the facility. These costs include purchasing additional calibration gases certified by EPA protocols, performing and analyzing daily zero and calibration checks on each monitoring instrument in accordance with the proposed rule, performing quarterly multi-point linearity checks of each analyzer, and performing annual relative accuracy test audits of each CO_2 or O_2 monitor and CEMs system. In addition, there will likely be an increase in labor costs as additional technicians may be needed to monitor and maintain the new instrumentation. The EPA estimate of total increased annual operating costs of this rule on a facility may be adequate to cover these costs for one new monitoring installation provided the new monitors are installed in an existing CEMs installation that monitors and reports gaseous pollutant emissions. However, the estimated incremental costs are inadequate for facilities that must certify numerous monitors according to the proposed rule.

Response: See the Preamble, Section II. L., for the response on the general monitoring approach. Please also see Section III. Y. 3. of the Preamble for EPA's response regarding our revised cost estimates for petroleum refineries. Specifically, we added relevant costs for existing monitors that may have been installed for process control purposes but that are not currently required to perform calibration checks or other QA/QC activities. However, we also note that many of the monitoring alternatives provided in the rule are not EPA protocols. The final rule generally allows calibration and maintenance of the monitoring systems according to manufacturer's specifications or according to the requirements of applicable methods from consensus standard organizations. While we anticipate these QA/QC requirements will provide quality-assured data adequate for the purposes on this final rule, they are expected to be somewhat less rigorous and less burdensome than typical EPA protocols to which the commenter appears to refer. Note that EPA's cost estimates are annualized and do not widely differ from the capital cost cited in this comment, although we are unaware of any application in which a CO_2 analyzer system would have capital costs approaching $500,000. We expect that what the commenter referred to as a "major facility upgrade" includes costs in addition to those that are required for compliance with the final rule. Further detail on the engineering cost analysis for Subpart C can be found in RIA (EPA-HQ-OAR-2008-0318-002), Section 4.3. We believe our revised costs accurately portray the burden associated with the final reporting requirements.

Commenter Name: Keith A. Nagel
Commenter Affiliation: ArcelorMittal USA and Severstal North America
Document Control Number: EPA-HQ-OAR-2008-0508-0496.1
Comment Excerpt Number: 25

Comment: EPA's stated rationale for requiring facilities with CEMS that do not monitor CO_2 to "upgrade" to CO_2 CEMS is that the "incremental cost" will not be unduly burdensome. 74 Fed. Reg. at 16483. In all scenarios except where CO_2 CEMS are already in place, actual costs would be more burdensome than EPA suggests. One primary reason is that EPA's capital cost estimates are based on "annualized costs over a 15-year timeframe." EPA-HQ-OAR-2008-0508-0002 at p. 4 - 22. While CO_2 CEMS may operate for 15 years (as EPA presumes), the real world cash-flow impact of such capital improvements cannot be similarly deferred. Rather, contractors require payment in full no later than the date of installation. Given the challenging economic climate and existing budget constraints, payment of lump-sum capital costs for many simultaneous upgrades (even assuming the actual amount of those costs matches EPA's estimates) will create a significant economic burden. Assessing whether that significant burden is "undue" also requires assessment of the relative benefits expected. The Tier 4 approach appears to provide, at most, very marginal improvement over Tier 3 reporting. As acknowledged in the preamble, "for combustion sources, the emission rate of CO_2 is directly proportional to the carbon content of the fuel, and virtually all of the carbon is oxidized to CO_2." 74 Fed. Reg. at 16480. Since Tier 3 requires careful monitoring of fuel carbon content and "virtually all" the measured carbon becomes CO_2, this methodology is more than accurate enough to achieve Congress' expressed goal: the collection of sufficient information to guide future legislative and regulatory efforts. 74 Fed. Reg. at 16456.[11] Since CO is strictly regulated, facilities will have no incentive to overestimate CO emissions (which would, in turn, reduce reported GHGs). If estimates are good enough to report CO emissions under active permits, then they should also suffice for CO_2 emissions reporting purposes. Indeed, the only expected difference between the Tier 3 and Tier 4 protocols is that Tier 3 reporting may modestly overestimate CO_2 emissions where incomplete combustion results in low-level CO emissions. As noted above, that adjustment can be made simply and accurately for many sources without any additional costs. Thus, the real-world difference in Tier 3 and Tier 4 reporting cannot justify the proposed mandatory imposition of significant up-front capital costs. It would be regulatory overkill to require sources to track down such minute carbon overestimates when the rule claims to cover only 85% of national GHG emissions and exempts all sources under 25,000 metric tons per year. Accordingly, we request that EPA limit mandatory Tier 4 reporting to only units that already have functioning CO_2 CEMS.

Response: See the Preamble, Section II. L., for EPA's response on the general monitoring approach.

EPA is requiring the use of CEMS for solid fossil fuel-fired units with installed CEMS that are required by applicable Federal or State regulation or the unit's operating permit due to the complexity of monitoring solid fuel consumption and the heterogeneous nature of the solid fuels. EPA has considered the commenter's analysis, but disagrees with the commenter's assessment of the burden associated with installing and maintaining the concentration and volume monitors that the rule requires be added to an existing CEMS. In the revised rule, the EPA has clarified that if the unit in question meets all six criteria then a CO_2 or O_2 and a stack gas volumetric flow rate monitor would be required to be installed. EPA's estimates of monitoring costs are averages for a representative facility and may not represent the actual cost in individual circumstances.

Commenter Name: Keith A. Nagel
Commenter Affiliation: ArcelorMittal USA and Severstal North America
Document Control Number: EPA-HQ-OAR-2008-0508-0496.1
Comment Excerpt Number: 22

Comment: Steel companies need the flexibility to use alternate methods for calculating GHG emissions from their combustion sources. As written, the Proposed Rule would require at least Tier 3 reporting for many steel plant combustion sources because those sources are larger than 250 mmBtu and/or combust blast furnace gas and/or coke oven gas (which have no default factors). The proposed Tier 3 rules would necessitate calculations based on daily sampling and analysis of fuel carbon content, molecular weight and quantity. Conducting such daily sampling and analysis of process gases plant-wide would be prohibitively expensive. For example, periodic coke oven gas sampling for a particular unit at ArcelorMittal's Burns Harbor facility costs $770 for a single daily sample set. Thus, daily sampling and analysis of just coke oven gas could cost more than $280,000 annually per unit.

Response: EPA acknowledges the concerns of the commenter, and has revised the final rule to include default factors for coke oven and blast furnace gases in Table C-1. In addition, EPA has attempted to clarify measurement procedures that will provide flexibility and minimize burden where initial prescriptions were impractical. While the revised rule does require daily sampling and analysis where the equipment is in place, if this equipment is not in place, weekly sampling and analysis may be used. If sampling and analysis occur at less than the minimum frequency, appropriate substitute data values shall be used in the emissions calculations, in accordance with §98.35.

Commenter Name: Matt Smorch
Commenter Affiliation: Countrymark Cooperative, LLP
Document Control Number: EPA-HQ-OAR-2008-0508-1081.1
Comment Excerpt Number: 4

Comment: Countrymark takes issue with EPA's estimate for implementing Continuous Emission Monitoring Systems (CEMS). The estimate of approximately $9,500 per refinery does not include the cost of installation, infrastructure, and supporting systems needed to insure quality CEMS installation and operation. Countrymark estimates the cost to be near $200,000. This is especially true if additional CEMS is required for the CCR platformer, flare system, and on-stream hydrocarbon composition determination.

Response: See the Preamble, Section II. L., for EPA's response on the general monitoring approach. Also, please see Section III. Y. 3. of the Preamble for EPA's response regarding final requirements for flares and the revised cost estimates for refineries.

We note that CEMS are not required in either Subpart C or Subpart Y unless they are already in-place and meet certain criteria as indicated in Subpart C, and then only for selected sources. If CEMS are not in place, they are not required to be installed. As such, we clarify that the installation of new CEMS are not required for catalytic reforming units (e.g., CCR platformers), flares, or other sources at the refinery. As a point of clarification, we interpret the comment regarding CEMS for flare systems to refer to continuous flow and composition monitoring of the flare gas, rather than an "emissions" monitoring system. The final rule in Subpart Y requires the use of the Tier 3 Calculation Methodology (specifically Equation C-5 in Subpart C of the final rule) for combustion units using fuel gas. Tier 3 requires daily monitoring of composition only when appropriate equipment is in place; otherwise weekly sampling allowed. The provisions for flares are similar, but also include higher heating value monitoring alternative and an engineering estimation method.

Also, we note that we do not require $CO_2/CO/O_2$ monitoring systems for catalytic cracking units with capacities of 10,000 bbls/day or less because these units are smaller GHG emission sources and are most likely to not have existing monitoring systems. For these sources, we allow engineering estimates as an alternative to the use of a $CO_2/CO/O_2$ monitoring system when a monitoring system in not already in-place. If a facility does need to install a monitoring system, then the capital costs that we estimated for such systems are not vastly different than those cited by the commenter. However, please note that EPA's costs are annualized, and are averages for a representative facility. In determining the average cost, EPA assumed that only a small percentage of facilities would need to install these monitors. Further detail on the engineering cost analysis for Subpart C and Subpart Y can be found in RIA (EPA-HQ-OAR-2008-0318-002), Section 4.3 and 4.17, respectively.

Commenter Name: Edward N. Saccoccia
Commenter Affiliation: Praxair Inc.
Document Control Number: EPA-HQ-OAR-2008-0508-0977.1
Comment Excerpt Number: 4

Comment: §98.33(b)(5)(ii)(E) imposes the Tier 4 method if the source has any existing CEMS system. Depending on the type of gas monitoring system a source may have (extractive vs. in-situ; wet vs. dry, etc.) the addition of a CO_2 CEMS can be a very costly modification. Modifications could include, assuming it is even technically feasible, the addition of stack sampling ports, addition of extractive sampling systems, sample conditioning systems, calibration gas systems and modification to data acquisition and reporting systems and software. These modifications can impose $40,000 to $250,000 of capital costs, as well as ongoing maintenance and operating costs for such units. As stated above, these costs may be imposed on the false premise that direct emission measurement via CEMS is an inherently more accurate than alternative calculation methods (e.g. Tiers 1, 2, or 3).

Response: See the Preamble, Section II. L., for EPA's response on the general monitoring approach.

It is EPA's view that direct measurement can be more accurate than calculation methods in certain circumstances, and the final rule reflects this view. EPA is requiring the use of CEMS for solid fossil fuel-fired units due to the complexity of monitoring solid fuel consumption and the heterogeneous nature of the solid fuels. EPA has considered the commenter's analysis, but disagrees with the commenter's assessment of the burden associated with installing and maintaining the concentration and volume monitors that the rule requires be added to an existing CEMS. In the revised rule, EPA has clarified that if the unit in question meets all six criteria then a CO_2 or O_2 and a stack gas volumetric flow rate monitor would be required to be installed. EPA's estimates of monitoring costs are averages for a representative facility and may not represent the actual cost in individual circumstances. Note that EPA's cost estimates are annualized and do not widely differ from the capital cost cited in this comment. Further detail on the engineering cost analysis for Subpart C can be found in RIA (EPA-HQ-OAR-2008-0318-002), Section 4.3.

Commenter Name: Ted Michaels
Commenter Affiliation: Energy Recovery Council (ERC)
Document Control Number: EPA-HQ-OAR-2008-0508-0544.1
Comment Excerpt Number: 2

Comment: The Increased Costs for Installing Part 75-like CEMS Are Not Justified As the WCI recognized, the substantial costs to implement Tier 4 methodology are very difficult to justify since the Tier 2 methods provide CO_2 emissions of sufficient accuracy. All MWC facilities have state-of-the-art wet or dry extractive Part 60 CEMs that use O_2 for diluent correction. None of the facilities have stack gas flow monitors, only a few have Part 60 certified CO_2 CEMS, and all facilities with dry-based CEMS do not have moisture monitoring. Consequently, for all large MWCs nationally, extensive CEM retrofits will be required to comply with Tier 4 including: 1. Installation of stack flow monitors; 2. Installation of moisture monitors for dry based systems; 3. Installation of CO_2 analyzers and integration into existing CEMs; 4. Plant modifications and integration including: installation of stack flow monitor ports, signal and power wiring, wiring tray or conduit and new access platforms (depending on suitable flow monitor location); 5. New CEM data systems for automatic data substitution and reporting; and 6. Initial certification of flow monitoring systems and CO_2 analyzers. Based upon cost estimates from approved CEMS equipment vendors at one of ERC members companies, estimated costs for installation of Tier 4 monitoring would range up to $4.5 million, with annual operating costs of a half a million dollars. Further, the purchase, installation, startup and certification process for the new equipment would likely delay reporting of 2010 emissions data collection and subsequent reporting.

Response: See the Preamble, Section II. L., for EPA's response on the general monitoring approach.

EPA is requiring the use of CEMS for larger solid fossil fuel-fired units due to the complexity of monitoring solid fuel consumption and the heterogeneous nature of the solid fuels. EPA has considered the commenter's analysis, but disagrees with the commenter's assessment of the burden associated with installing and maintaining the concentration and volume monitors that the rule requires be added to an existing CEMS. In the revised rule, EPA has clarified that if the unit in question meets all six criteria then a CO_2 or O_2 and a stack gas volumetric flow rate monitor would be required to be installed. EPA's estimates of monitoring costs are averages for a representative facility and may not represent the actual cost in individual circumstances.

As a result of commenters' legitimate concern on timing, EPA has revised the initial reporting approach for the final rule. See the Preamble, Section II. G., "Summary of Comments and Responses on Initial Reporting Year and Best Available Monitoring Methods," for more information on additional flexibility provided to reporters for 2010.

Commenter Name: See Table 7
Commenter Affiliation:
Document Control Number: EPA-HQ-OAR-2008-0508-0412.1
Comment Excerpt Number: 26

Comment: Natural gas systems will also need to comply with Subpart C - General Stationary Fuel Combustion Sources. These sources bear the second highest burden of all regulated entities - 17% of all first year total annualized costs and 15% of first year capital costs. EPA has estimated that, in order to measure the cumulative 6% of GHG emissions produced by sources regulated under Subpart C, sources will need to incur on average first year total annualized costs of $10,000 based upon a total cost estimate of $29.0 million for 3,000 sources. These additional costs exacerbate the cost-benefit imbalance that arises under Subpart W. Requiring sources that are regulated under Subpart W to bear the additional expenses of direct measurement to quantify these small emissions will impose a great financial burden on particular states such as New Mexico, Oklahoma, and Texas that maintain a large portion of the nation's oil and natural gas industry.

Response: See the Preamble, Section III. C., on the method for calculating emissions.

EPA acknowledges the commenters' concerns regarding natural gas sampling costs, and has revised the §98.34 as follows: for natural gas, semiannual sampling and analysis is required. Furthermore, EPA has revised Subpart C so that units of any size combusting only pipeline quality natural gas and/or distillate oil may use Tier 2 methods. EPA points out that it is not finalizing Subpart W at this time.

Commenter Name: Lloyd Stone
Commenter Affiliation: Westlake Chemical Corporation
Document Control Number: EPA-HQ-OAR-2008-0508-0442.1
Comment Excerpt Number: 6

Comment: Although CEMS are in use at some of our facilities, CO_2 CEMS are not used as the diluent monitor, and flow meters are not in prevalent use either. The purported cost of compliance with Subpart C is also underestimated in the Regulatory Impact Analysis for the Mandatory Reporting of Greenhouse Gas Emissions Proposed Rule (GHG Reporting). One example is that the RIA's Annualized First costs estimates should only be made for support facilities and CEMS hardware (fixed assets). Tables 4-2f, 4-2g, 4-2h, and 4-2i represent the other ODC costs as non-annualized First time costs just like Labor and Consultant costs. Whereas, the other ODC costs (Planning, Select equipment, Install and check CEMS, and Performance specification tests) are annualized in Table 4-2a. In Table 4-2a, the final value of $56,040 becomes $60,544 when only the support facility and CEMS costs are annualized. That is an 8% error multiplied several times over for the 3000 entities that EPA estimates is impacted by the 25,000 metric tons CO_2e. A second example is that the CEMS/flow meter maintenance costs do not appear to be included in the annual costs, overlooking another substantial cost of compliance. A third example is that no Labor costs are shown for purchasing CEMS equipment in Tables 4-2a, 4-2b, and 4-2c. Purchase orders do not automatically generate once a technician/engineer makes the equipment selection. Purchasing employees' time should be accounted for as a result. A final example on cost discrepancies is that EPA does not include costs for the data acquisition and management (i.e., software), and data quality assurance/quality control (via the mandated written quality assurance performance plan). Westlake has already begun the process of evaluating software designed to handle the management of GHG data. The costs are in the 100,000's of dollars for purchasing and implementing this needed software.

Response: See the Preamble, Section II. L., for EPA's response on the general monitoring approach.

EPA does not agree with the commenter's first example that annualized costs in the RIA should not include ODC costs. In fact, all of the tables cited in the comment breakdown planning and equipment costs between labor performed by employees and work performed by a contractor. ODC costs includes the latter. EPA believes that apportioning some planning and equipment selection costs to a contractor is the most realistic assumption to make. EPA does not agree with the commenter that CEMS maintenance costs are not included in Tables 4-2a, 4-2b, and 4-2c. The line item 'Purchase CEMS hardware' in Table 4-2a is the cost of the CEMS hardware. Labor for purchasing CEMS equipment in the same table is provided under Planning ($3,477) and Select equipment ($9,281). EPA also does not agree with the commenter's final examples that costs for software or quality assurance/quality control are not included. DAHS software costs are provided for in the line item Purchase CEMS hardware. Costs for quality assurance/quality control are shown on line items QA/QC plan and Annual QA and O&M review and update. For further detail on the Subpart C engineering cost analysis, please see the Final RIA (EPA-HQ-2008-0508) and the cost appendix to the RIA.

EPA is requiring the use of CEMS for solid fossil fuel-fired units due to the complexity of monitoring solid fuel consumption and the heterogeneous nature of the solid fuels. EPA has considered the commenter's analysis, but disagrees with the commenter's assessment of the burden associated with installing and maintaining the concentration and volume monitors that the rule requires be added to an existing CEMS. In the revised rule, EPA has clarified that if the unit in question meets all six criteria then a CO_2 or O_2 and a stack gas volumetric flow rate monitor would be required to be installed. EPA's estimates of monitoring costs are averages for a representative facility and may not represent the actual cost in individual circumstances. .

Commenter Name: Henry Derwent
Commenter Affiliation: International Emissions Trading Association (IETA)
Document Control Number: EPA-HQ-OAR-2008-0508-0512.1
Comment Excerpt Number: 5

Comment: The proposal envisages that going forward, Continuous Emissions Monitors (CEMS) will be a requirement only in those sectors and organizations where they are already required, mainly those in the existing SO_2 and NO_x programme. IETA supports this provision.

Industry studies have shown that installing CEMS costs between $165,000 to $200,000. Additionally, annual operating and maintenance costs would average around $63,000. If emergency services are required by a CEMS vendor, costs per day range from $1,200 to $1,600 plus portal to portal expenses and travel time to and from the site. Given these costs, IETA is opposed to requiring broader use of CEMS.

Response: EPA appreciates the commenter's input and thanks you for your comment. EPA notes that the requirements of this rule were not designed as part of implementing a specific cap and trade program, which is beyond the scope of the direction by Congress.

Commenter Name: Karin Ritter
Commenter Affiliation: American Petroleum Institute (API)
Document Control Number: EPA-HQ-OAR-2008-0508-2167.1
Comment Excerpt Number: 3

Comment: The following summarizes API member company feedback on parameters EPA used to develop the cost implications for Subpart C. The responses below represent feedback from 7 U.S. refineries, with capacities ranging from 50 to over 300 KBPCD (thousand barrels per calendar day). Subpart C (Stationary Combustion) Costs: API members indicated that the cost to install CO_2 monitors, flow meters, and analyzers to comply with the requirements of Subpart C could range from $500,000 to $7,000,000 per facility.

Response: EPA is requiring the use of CEMS for solid fossil fuel-fired units due to the complexity of monitoring solid fuel consumption and the heterogeneous nature of the solid fuels. EPA recommends that the commenter cross-check the facilities and units encompassed by the 7 U.S. refineries to see if the requirement to apply Tier 4 applies. EPA has considered the commenter's analysis, but disagrees with the commenter's assessment of the burden associated with installing and maintaining the concentration and volume monitors that the rule requires be added to an existing CEMS. In the revised rule, EPA has clarified that if the unit in question meets all six criteria in §98.33(b) then a CO_2 or O_2 and a stack gas volumetric flow rate monitor would be required to be installed. EPA's estimates of monitoring costs are averages for a representative facility and may not represent the actual cost in individual circumstances.

11. OTHER SUBPART C COMMENTS

Commenter Name: Patrick J. Nugent
Commenter Affiliation: Texas Pipeline Association (TPA)
Document Control Number: EPA-HQ-OAR-2008-0508-0460.1
Comment Excerpt Number: 20

Comment: TPA generally supports the requirements set forth in Subpart C related to combustion sources and commends EPA for the reasonable and clearly stated approach taken in that Subpart.

Response: EPA appreciates your support of the requirements set forth in Subpart C and thanks you for your comment.

Commenter Name: Lorraine Krupa Gershman
Commenter Affiliation: American Chemistry Council (ACC)
Document Control Number: EPA-HQ-OAR-2008-0508-0423.2
Comment Excerpt Number: 61

Comment: For the sampling requirements of §98.34(c) and (d)(3), EPA should allow sufficient time until the next scheduled process unit turnaround or December 2009, whichever is later, for installing sample taps or locations in order to collect the samples for carbon analysis, molecular weight determinations, and high heating value. These sampling locations may not exist today. Facilities should not be required to incur the cost of additional process unit shutdowns to install these taps, and in most cases, scheduled shutdowns will occur on a three to five year cycle.

Response: See the Preamble, Section III. C., on monitoring and QA/QC requirements.

EPA acknowledges the concerns of the commenter. The final rule allows sampling data from the fuel supplier to be used to meet Part 98 requirements. For unconventional gaseous fuels, daily sampling is required only where the necessary equipment is already in place. Otherwise, weekly sampling is required. The calibration deadline for fuel flow meters has been extended to April 1, 2010, with an exception for continuously operating processes, allowing calibration to coincide with the next scheduled maintenance outage. Additional flexibility has been added in the flow meter calibration methods. Industry consensus methods may be used. Also, flow meters with active calibrations as of April 1, 2010 (either according to the manufacturer's schedule or the industry consensus schedule), the April 1, 2010 deadline does not apply -- these meters may be recalibrated on their normal schedule.

Commenter Name: Lorraine Krupa Gershman
Commenter Affiliation: American Chemistry Council (ACC)
Document Control Number: EPA-HQ-OAR-2008-0508-0423.2
Comment Excerpt Number: 48

Comment: In §§98.33(a)(3) and (b)(4), units may not have measured fuel flow rates and flow measuring devices may not be installed. Installing this equipment in a short period of time may be impossible due to long equipment delivery times, competition for purchasing measuring devices at the same time and among the many entities subject to the greenhouse gas reporting requirements, and timing of outages of process units required to install the equipment. Many of these process units would not normally be taken out of service for three to five years. Such outages would be unnecessarily costly. EPA should allow an additional five years or at the next scheduled maintenance turnaround shutdown after December 2009 for facilities to install the required flow meters, whichever is later. In the interim, in lieu of measured flow rates, facilities should be allowed to use engineering calculations to determine flows.

Response: See the Preamble, Section III. C., on calculating CO_2 emissions from combustion. See the Preamble, Section II. G., on "Summary of Comments and Responses on Initial Reporting Year and Best Available Monitoring Methods" for additional information on flexibility provided for 2010.

EPA acknowledges the concerns of the commenter. The final rule allows sampling data from the fuel supplier to be used to meet Part 98 requirements. For unconventional gaseous fuels, daily sampling is required only where the necessary equipment is already in place. Otherwise, weekly sampling is required. The calibration deadline for fuel flow meters has been extended to April 1, 2010, with an exception for continuously operating processes, allowing calibration to coincide with the next scheduled maintenance outage. Additional flexibility has been added in the flow meter calibration methods. Industry consensus methods may be used. Also, flow meters with active calibrations as of April 1, 2010 (either according to the manufacturer's schedule or the industry consensus schedule), the April 1, 2010 deadline does not apply -- these meters may be recalibrated on their normal schedule.

12. CALCULATION OF BIOGENIC EMISSIONS

Commenter Name: Ron Downey
Commenter Affiliation: LWB Refractories
Document Control Number: EPA-HQ-OAR-2008-0508-0719.1
Comment Excerpt Number: 28

Comment: The formulas set forth in 40 CFR 98.33(e)(2) regarding how CEMS are used to calculate CO_2 emissions from the combustion of biomass or biomass-derived fuel is inappropriate for sources such as lime plants that have process emissions. The proposed formula assumes that if one was to subtract the volume of CO_2 from fossil fuel combustion from the total volume of CO_2, then the remaining CO_2 would be biogenic. In the case of the lime industry, the difference between total and combustion emissions would be comprised of biogenic and process emissions. LWB proposes that the following equation be added to 40 CFR 98.33(e)(2) to account for sources with process emissions: Total CO_2 tons – Fossil Fuel CO_2 tons – Process CO_2 tons = Biogenic Fuel CO_2 tons

Response: EPA appreciates that CEMS will capture both process and combustion emissions, and has revised the rule for units that burn biomass (not including MSW) and fossil fuels, have process emissions, and use a CEMS to measure CO_2. The revision to §98.33(e)(2) adds the subtraction of process emissions from the CEMS measured CO_2 to determine the biogenic emissions. The process CO_2 emissions must be calculated according to the requirements of the applicable subpart.

Commenter Name: Ted Michaels
Commenter Affiliation: Energy Recovery Council (ERC)
Document Control Number: EPA-HQ-OAR-2008-0508-0544.1
Comment Excerpt Number: 7

Comment: 98.33(e)(3) MSW Combustion. The calculations for MSW combustion focus on biogenic CO_2 which is not considered a GHG gas by IPCC or in any GHG reporting convention. Non-biogenic CO_2 or Anthropogenic only is included in total CO_2e emissions. Since only non-biogenic CO_2 is included in CO_2e total, Section 98.33(e)(5) should be revised to include calculation of non-biogenic CO_2 emissions derived from ASTM D 7459-08 and D 6866-06a methods. Non-biogenic fraction is 1-biogenic fraction as reported with ASTM D6866 results. If biogenic or biomass fraction is 0.30 then non-biogenic fraction in 1-0.30 or 0.70. Note also the biogenic fraction of 0.30 used in the example is incorrect. The national biogenic CO_2 average fraction for MSW combustion is approximately 60 - 70% (or 0.60 - 0.70).

Response: The IPCC identifies CO_2 as a GHG, as does the UNFCCC, the Inventory of U.S. Greenhouse Gases and Sinks, and all other reporting programs, and does not exclude biogenic CO_2. Biogenic CO_2 may be included in total CO_2 emissions at the national level if there are net changes in carbon stocks in land-based carbon pools (e.g., above ground biomass, soil carbon etc.). EPA has retained the use of the ASTM D6866-06a and D7459-08 methods in the final rule, and has expanded the use of these methods so that they may be used to calculate biogenic emissions from any unit which uses CEMS and combusts a combination of biogenic and non-biogenic fuels (other than MSW). However, EPA continues to believe that biogenic CO_2 emissions should be reported to EPA and included in emissions totals, although they should be tracked separately.

Commenter Name: Paul Dubenetzky
Commenter Affiliation: KERAMIDA Inc.
Document Control Number: EPA-HQ-OAR-2008-0508-0419.1
Comment Excerpt Number: 10

Comment: Many facilities are increasing the use of "biodiesel" as a fuel, either in compression ignition engines or in stationary combustion sources such as boilers. "Biodiesel" is typically a blend of methyl esters derived from plant or animal fat and "petrodiesel" derived from petroleum. For instance a blend of 20% methyl ester and 80% petrodiesel is commonly referred to as B20 biodiesel. Both the applicability provisions of 40 CFR 98.2(b)(2), 74 FR 16613 and the reporting requirement of 40 CFR 98.36(b)(4), 74 FR 16637 require that the GHG emissions from bio fuels and fossil fuels be accounted for separately. 40 CFR Subpart C, Table C-1, 74 FR 16639 contains CO_2 methodology for only "Distillate Fuel Oil (#1, 2, 3, 4) and "Other Oil (401 deg. F)" and Table C-3, 73 FR 16641 contains CH_4 and N_2O methodology for only "Distillate Oil". While there are reasonable interpretations of how to address the issue of GHG emissions from the combustion of "biodiesel," the U.S. EPA should provide a specific protocol to address the combustion of "biodiesel." KERAMIDA suggests that protocol include the 40 CFR 98, Subpart MM emission factors for CO_2 provided in Table MM3 for 100% methyl ester and a statement to the effect that the emissions from fuels that are a blend of biomass products and petroleum based products shall be calculated and reported based on their weight percent composition. The U.S. EPA should address gasoline containing ethanol in a similar matter using the CO_2 emission factor for ethanol found in Table MM-3 (40 CFR, Subpart MM Table 1, 74 FR 16719 & Table 3, 74 FR 16720 and 40 CFR 98, Subpart C, Table C-1, 74 FR 16639.

Response: EPA has clarified the rule as applied to biodiesel and ethanol blend fuels, and other biomass fuels. In §98.33(e), the use of the Tier 1 method is specified to calculate biogenic emissions from biogas and biodiesel, as well as other biomass fuels (except for MSW) listed in Table C-1. EPA has added emission factors to Table C-1 for liquid biomass-derived fuels including ethanol, biodiesel, rendered animal fat, and vegetable oil. For premixed fuels that contain biomass and fossil fuels (e.g., mixtures containing biodiesel), sources may use the best available information to determine the mass of biomass fuels and document the procedure used in the GHG Monitoring Plan.

Commenter Name: Louis Kollias
Commenter Affiliation: Metropolitan Water Reclamation District of Greater Chicago (District)
Document Control Number: EPA-HQ-OAR-2008-0508-0311
Comment Excerpt Number: 3

Comment: Is anaerobic biogas considered a biomass-derived fuel and therefore exempt from potential reporting?

Response: EPA considers anaerobic biogas a form of biomass-based fuel, as defined in §98.6. The definition states that "non-fossilized and biodegradable organic fractions of industrial and municipal wastes, including gases and liquids recovered from the decomposition of non-fossilized and biodegradable organic material" are considered biomass. EPA continues to believe that biogenic CO_2 emissions should be reported to EPA and included in emissions totals, although they should be tracked separately. In the final rule, Subpart C (Stationary Fuel Combustion Units) has been revised since proposal to require reporting of only biomass fuels listed in Table C-1 of Subpart C. In the revised §98.33(e), EPA has specified that emissions from biogas and other biomass fuels listed in Table C-1 (except for MSW) are to be calculated using Tier 1. EPA has added default values for biogas in Table C-1.

Commenter Name: See Table 1
Commenter Affiliation:
Document Control Number: EPA-HQ-OAR-2008-0508-0278
Comment Excerpt Number: 1

Comment: In several sections of the proposed greenhouse gas reporting protocol, the EPA solicits comments on how to better quantify the biomass fraction of fuels. There is a readily available method called ASTM D6866 that can precisely and accurately quantify the biomass fraction of any type of fuel or material (gas, liquids, or solids). This method is already adopted in the current reporting rule under the Tier 4 sampling protocol for municipal solid waste (pages 16636 to 16639). The EPA should broaden the use of this method for all fuels and materials since municipal solid waste is in essence a heterogeneous fuel / material. The ASTM D6866 method is a standardized version for industrial use of radiocarbon dating, an analytical technique that was developed in the 1950s. Radiocarbon dating has been used for decades for dating archaeological artifacts. The same principles of dating (i.e. analysis of the carbon-14 atom) can also be used to measure the biomass component of fuels and materials. Biomass contains a well-characterized amount of carbon-14 that is easily distinguished from other materials such as fossil fuels that do not contain any carbon-14. Since the amount of carbon-14 in biomass is well known, a percentage of biogenic carbon (or in the case of a gas sample, biogenic CO_2) can be calculated easily from the overall carbon atoms (or CO_2) in the sample. Although ASTM D6866 is now used throughout the world to measure biomass carbon / CO_2, the origins of the method are American. It was written at the request of the USDA to satisfy legislation requiring federal agencies to prefer procurement from manufacturers using the greatest amount of biomass in their products (per the Farm Security and Rural Investment act of 2002). It was quickly established that radiocarbon dating was the only viable and accurate technique to make the determination of the biomass percentage. A working standard of radiocarbon dating for industrial use was completed in 2004 and is now cited in US Federal Law (7 CFR part 2902). We believe that the ASTM D6866 method should be allowed for all heterogeneous fuels (i.e. those that contain a biomass fraction), not just municipal solid waste as cited in the current EPA greenhouse gas reporting rule. The EPA should expand the use of ASTM D6866 to include all heterogeneous and alternative fuels, including those referenced in Table C-2 on page 16640 of the EPA protocol. Current regional protocols in the US, such as California's AB 32 and the Western Climate Initiative, allow the use of ASTM D6866 for heterogeneous fuels. Below are two links where ASTM D6866 is cited for heterogeneous fuels in these two protocols: California's AB32: (Operator advised to use ASTM D6866 to determine CO_2 emissions from the combustion of biomass, municipal solid waste, or waste-derived fuels with biomass.) Page 93, http://www.arb.ca.gov/regact/2007/ghg2007/frofinoal.pdf Western Climate Initiative: (Operator that combusts fuels or fuel mixtures that contain biomass shall determine the biomass-derived portion of CO_2 emissions using ASTM D6866.) Page 79, http://www.westernclimateinitiative.org/ewebeditpro/items/O104F20744.pdf The European Union also allows the use of carbon-14 for measuring heterogeneous fuels, particularly for solid recovered fuels (SRF) and refuse-derived fuels (RDF). A carbon-14 method called CEN/TS 15747:2008 was developed for these types of fuels. It is almost identical to ASTM D6866. In fact, CEN/TS 15747:2008 cites ASTM D6866 as the premise for the method. In 2007, the European Union published a FAQ for the EU Emissions Trading Scheme. On pages 16 and 17, carbon-14 is cited as an acceptable method for determining the biogenic fraction of heterogeneous fuels. Both ASTM D6866 and CEN/TR 15991:2007 (precursor to CEN/TS 15747:2008) are cited as acceptable carbon-14 methods. The EU ETS FAQ can be found at this link: http://ec.europa.eu/environment/climat/emission/pdf/mrg2faq_sep_2007.pdf. Of course, it must be noted that Europe, California, and the Western Climate Initiative are not the only entities advocating the use of carbon-14 for heterogeneous fuels. Australia has also advocated its use, particularly for blended fuels. More information on the Australian protocol can be found here (see pages 114 to 115): http://www.climatechange.gov.au/reporting/publications/pubs/nger-technical-guidelines-v1-1.pdf. Lastly, we would like to add that The Climate Registry's Greenhouse Gas Reporting Protocol (please see page 65) also advocates the use of ASTM D6866 for biomass derived fuels. More information can be found at this link: http://www.theclimateregistry.org/downloads/GRP.pdf. In light of the acceptance of the ASTM D6866 method for all heterogeneous fuels, we believe that the method should be allowed for all fuel types (i.e. gas, liquids or solids). The method works equally well for any material. Under certain circumstances (e.g. plant operators without CEMS), sampling the liquid or solid fuel itself might make more sense. Of course, it is better to sample the final CO_2 emission to determine the biogenic fraction from the combustion. Nonetheless, there are situations where analyzing the liquid or solid fuel is more economical, particularly if a representative sample can be submitted to the laboratory. This is often the case for the cement industry that is concurrently doing a host of other tests on their solid fuels. In that regard, the CEN/TS 15747:2008 method was created in Europe because the cement and paper/pulp industries are important users of SRF/RDF. They perform a host of tests on the SRF/RDF itself, along with the biogenic fraction determination. On that note, the EU ETS FAQ cited before contains sampling recommendations on page 17 for liquid and solid fuels. We would like to mention that the ASTM D6866 method would address perfectly the concerns cited in Section V, Subpart MM (pages 16569 to 16575). The method can determine unambiguously the biomass fraction of any fuel mix. For example, synthetic ethanol made from fossil fuels is chemically indistinguishable from bioethanol made from a biomass feedstock. ASTM D6866 is the only method that can determine precisely the percentage of biocarbon in the fuel mix. In a similar light, the ASTM D6866 can help resolve biocarbon fraction ambiguities in complex fuel mixes such as Hydrogenation-Derived Renewable Diesel (HDRD). Lastly, we would like to suggest that the Tier 4 calculation allow the use of ASTM D6866 to calculate the biogenic CO_2 fraction of any waste fuel or material, not just municipal solid waste. Since the ASTM D6866 method works equally well for any waste materials that contain a biomass fraction, the EPA protocol should include along with municipal solid waste, the use of ASTM D6866 for any waste materials, waste fuels, tires and alternative fuels in the Tier 4 biogenic calculation protocol. In summary, we are advocating through this public comment that the EPA should allow the use of ASTM D6866 for all heterogeneous/alternative fuels (i.e. those that contain a biomass fraction) to determine the biogenic percentage. We are also advocating that plant operators be allowed to use the ASTM D6866 method to determine the biogenic fraction on the fuel itself when gas sampling is difficult. Contrary to emission factors or other methods (e.g. manual sorting), the carbon-14 method can accurately determine the biogenic fraction on any type of fuel (gas, liquid, or solid). As can be seen with the national and international GHG protocols cited in this comment, the ASTM D6866 method has been accepted widely throughout the world for the measurement of the biogenic fraction of heterogeneous fuels. It is important that the EPA GHG protocol adopt similar reporting methods to ensure that CO_2 emissions calculated in the United States are the same as the CO_2 emissions calculated with these other protocols.

Response: EPA appreciates the commenter's support of the ASTM methods. In §98.33(e)(4) of the final rule, EPA has laid out the use of the ASTM D6866-06a and D7459-08 methods so that they may be used to calculate biogenic emissions from any unit using CEMS and combusting a combination of biogenic and non-biogenic fuels (other than MSW). In situations where CEMS are not used, however, EPA has provided for biogenic emissions to be calculated using Tier 1 methods.

Commenter Name: Louis Kollias
Commenter Affiliation: Metropolitan Water Reclamation District of Greater Chicago (District)
Document Control Number: EPA-HQ-OAR-2008-0508-0311
Comment Excerpt Number: 1

Comment: Should the District ever operate sewage sludge incinerators, it is unclear exactly what calculation method would be used. However, NACWA believes that the ruling's Tier 2 Calculation Methodology would be used. However, calculation would be difficult due to the variability in the heating value of sludge and the lack of emission factors provided in the proposed ruling. It is unclear in NACWA's review why they consider biogas, but not sewage sludge, a biomass-derived fuel.

Response: In the final rule, Subpart C (Stationary Fuel Combustion Units) has been revised since proposal to require reporting of only those biomass fuels listed in Table C-1 of Subpart C. EPA has clarified this table, and sewage sludge is not included. Therefore, emissions from sewer sludge would not be reported.

Commenter Name: Robert D. Bessette
Commenter Affiliation: The Council of Industrial Boiler Owners (CIBO).
Document Control Number: EPA-HQ-OAR-2008-0508-0513.1
Comment Excerpt Number: 34

Comment: Biogenic CO_2 emissions methodology does not address liquid fuels that are derived from biogenic sources, e.g., liquid byproduct streams from biological transformation processes. Those streams should be treated similarly to biogas combustion in that either Tier 2 or Tier 3 methodology could be used. However, analyses of both biogenic liquids and biogases derived from processing where analyses do not vary significantly over time should be allowed to use periodic analyses or engineering determinations of quality for determining annual biogenic CO_2 emissions. Such periodic evaluations could be based on initial determinations and then subsequently upon significant changes to the process.

Response: In preparation of the final rule, EPA has added a provision to §98.33(e) allowing the use of Tier 1 methods to calculate biogenic emissions from most biogenic fuels listed in Table C-1. If the biogenic fuels consist of biogas or biodiesel and the HHV is sampled at the minimum required frequency (quarterly), Tier 2 shall be used instead. EPA has added emission factors to Table C-1 for liquid and gaseous biomass-derived fuels including biogas, ethanol, biodiesel, rendered animal fat, and vegetable oil. For premixed fuels that contain biomass and fossil fuels (e.g., mixtures containing biodiesel), sources may use the best available information to determine the mass of biomass fuels and document the procedure used in the GHG Monitoring Plan.

Commenter Name: Chris Hornback
Commenter Affiliation: National Association of Clean Water Agencies (NACWA)
Document Control Number: EPA-HQ-OAR-2008-0508-0566.1
Comment Excerpt Number: 11

Comment: EPA should provide more detail or specific examples in its definition of biomass. NACWA believes based on its reading of the proposal that biosolids or sewage sludge would be considered a biomass fuel, but it is not absolutely clear that this is consistent with EPA's intent.

Response: EPA has finalized the definition of biomass as proposed. In the final rule, Subpart C (Stationary Fuel Combustion Units) has been revised since proposal to require reporting of only biomass fuels listed in Table C-1 of Subpart C. EPA has clarified this table, and sewage sludge is not included. Therefore, emissions from sewage sludge would not be reported.

Commenter Name: Lorraine Krupa Gershman
Commenter Affiliation: American Chemistry Council (ACC)
Document Control Number: EPA-HQ-OAR-2008-0508-0423.2
Comment Excerpt Number: 29

Comment: The definition of biomass should be expanded to encompass materials resulting from biofuels production or bio-based materials processing. We recommend that the definition should be revised as follows: "…including products, by-products, residues and waste from agriculture, forestry and related industries, biofuels and bio-based materials industries, as well as the non-fossilized…" This change is to clarify the source of materials for inclusion in biogenic CO_2 emissions.

Response: In response to the comment, EPA does not believe that any additional language is needed to address the biomass definition. Biomass means non-fossilized and biodegradable organic material originating from plants, animals and/or micro-organisms, including products, by-products, residues and waste from agriculture, forestry and related industries as well as the non-fossilized and biodegradable organic fractions of industrial and municipal wastes, including gases and liquids recovered from the decomposition of non-fossilized and biodegradable organic material. In §98.6 of the final rule, the definition states that organic material originating from products and byproducts from agriculture, forestry and related industries are defined as biomass. Biofuels derive from agricultural sources, and therefore it is implied that they would fall under this definition. Table C-1 in the General Stationary Combustion subpart has been revised to provide default values for more biogenic fuels.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2008-0508-0513.1
Comment Excerpt Number: 15
Form Letter? No

Comment: The definition of biomass should be expanded to encompass materials resulting from biofuels production or bio-based materials processing. CIBO recommends this revised text: "…including products, by-products, residues and waste from agriculture, forestry and related industries, biofuels and bio-based materials industries, as well as the non-fossilized…" This change is to clarify that source of materials for inclusion in biogenic CO_2 emissions.

Response: EPA has clarified the definition of biomass in the rule. Biomass means non-fossilized and biodegradable organic material originating from plants, animals and/or micro-organisms, including products, by-products, residues and waste from agriculture, forestry and related industries as well as the non-fossilized and biodegradable organic fractions of industrial and municipal wastes, including gases and liquids recovered from the decomposition of non-fossilized and biodegradable organic material. It has also clarified the list of fuels in Table C-1, which would be expected to be reported using the Tier 1 Calculation Methodology.

Table 1

COMMENTER	AFFILIATE	DCN
Thierry Sam Tamers	Beta Analytic Limited	EPA-HQ-OAR-2008-0508-0278
Maurico Larenas	Beta Analytic Limited	EPA-HQ-OAR-2008-0508-0307.1

Table 2

COMMENTER	AFFILIATE	DCN
Michel R. Benoit	Cement Kiln Recycling Coalition (CKRC)	EPA-HQ-OAR-2008-0508-0467
Andrew T. O'Hare	Portland Cement Association (PCA)	EPA-HQ-OAR-2008-0508-0509.1

Table 3

COMMENTER	AFFILIATE	DCN
James Greenwood	Valero Energy Corporation	EPA-HQ-OAR-2008-0508-0571.1 EPA-HQ-OAR-2008-0508-0571.2
Charles T. Drevna	National Petrochemical and Refiners Association	EPA-HQ-OAR-2008-0508-0433.1 EPA-HQ-OAR-2008-0508-0433.2

Table 4

COMMENTER	AFFILIATE	DCN
Olon Plunk	Xcel Energy Inc.	EPA-HQ-OAR-2008-0508-0444
Debra J. Jezouit	Class of '85 Regulatory Response Group	EPA-HQ-OAR-2008-0508-0455.1

Table 5

COMMENTER	AFFILIATE	DCN
Lisa Beal	Interstate Natural Gas Association of America (INGAA)	EPA-HQ-OAR-2008-0508-0480.1
Richard Bye	CenterPoint Energy, Inc.	EPA-HQ-OAR-2008-0508-2124.1
Brianne Metzger	Spectra Energy Corporation	EPA-HQ-OAR-2008-0508-0364.1

Table 6

COMMENTER	AFFILIATE	DCN
Karin Ritter	American Petroleum Institute (API)	EPA-HQ-OAR-2008-0508-0679.1
James Greenwood	Valero Energy Corporation	EPA-HQ-OAR-2008-0508-0571.1
William W. Grygar II	Anadarko Petroleum Corporation	EPA-HQ-OAR-2008-0508-0459.1

Table 7

COMMENTER	AFFILIATE	DCN
Johnny R. Dreyer	Gas Processors Association (GPA)	EPA-HQ-OAR-2008-0508-0412.1
William W. Grygar II	Anadarko Petroleum Corporation	EPA-HQ-OAR-2008-0508-0459.1

Table 8

COMMENTER	AFFILIATE	DCN
Pamela A. Lacey	American Gas Association (AGA)	EPA-HQ-OAR-2008-0508-0709.1
Richard Bye	CenterPoint Energy, Inc.	EPA-HQ-OAR-2008-0508-2124.1

Table 9

COMMENTER	AFFILIATE	DCN
Chris Hobson	The Southern Company	EPA-HQ-OAR-2008-0508-1645.1
Quinlan J. Shea, III	Edison Electric Institute (EEI)	EPA-HQ-OAR-2008-0508-1021.1

Table 10

COMMENTER	AFFILIATE	DCN
Craig Holt Segall	Sierra Club	EPA-HQ-OAR-2008-0508-0635.1
Melissa Thrailkill	Center for Biological Diversity	EPA-HQ-OAR-2008-0508-0430.1