

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

Revision of Certain Provisions of the Mandatory Reporting of Greenhouse Gases Rule

November 2010

Revision of Certain Provisions of the Mandatory Reporting of Greenhouse Gases Rule

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

FOREWORD

This document provides EPA's responses to public comments on EPA's Proposed Revision of Certain Provisions of the Mandatory Reporting of Greenhouse Gases Rule. EPA published a Notice of Proposed Rulemaking in the Federal Register on August 11, 2010 (75 FR 48744). EPA received comments on this proposed rule via one or more of the following methods: regulations.gov, e-mail, fax, mail or courier. Copies of all comments submitted are available at the EPA Docket Center Public Reading Room. Comment letters are also available electronically through <http://www.regulations.gov> by searching Docket ID *EPA-HQ-OAR-2008-0508*.

This Response to Comments document provides the verbatim text of comments extracted from the original comment letter. 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.

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 the selection of source categories to report and the level of reporting 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 all sections of this document with subject areas that may be relevant to the reader's subpart(s) of interest.

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TABLE OF CONTENTS

<u>Section</u>	<u>Page</u>
1. HOW THESE AMENDMENTS APPLY TO 2011 GHG EMISSION REPORTS	1
2. SUBPART A – GENERAL PROVISIONS	8
Applicability threshold for natural gas LDCs.....	8
Content of annual report- separate biogenic CO ₂ emissions reporting.....	11
Content of annual report- other amendments.....	41
Recordkeeping	41
Revisions to the annual GHG report.....	47
Calibration and accuracy requirements.....	56
Measurement device installation.....	74
Definition of agricultural byproducts.....	82
Definition of municipal solid waste (MSW).....	83
Definition of natural gas	90
Definition of waste oil	91
Definition of wood residuals.....	93
Other definitions	95
Standardized methods incorporated by reference	101
Other Subpart A comments.....	103
3. SUBPART C – GENERAL STATIONARY FUEL COMBUSTION	108
Definition of source category.....	108
Tier 1 Calculation Methodology.....	109
Tier 2 Calculation Methodology.....	113
Tier 4 Calculation Methodology.....	122
Tier 1 Applicability.....	128
Tier 2 Applicability.....	129
Tier 3 Applicability.....	130
Tier 4 Applicability.....	132
CH ₄ and N ₂ O emissions	138
Biogenic CO ₂ emissions	140
Monitoring and QA/QC requirements	152
4. SUBPART D - ELECTRICITY GENERATION	194
5. SUBPART F - ALUMINUM PRODUCTION	195
Other Subpart F Comments	195
6. SUBPART G - AMMONIA MANUFACTURING	195
Purge Gas/Recycle Stream.....	195
Proposed Deletion of Synthetic Fertilizer Reporting.....	196
Other Subpart G Comments.....	200
7. SUBPART P - HYDROGEN PRODUCTION	201
Oil and Gas Flow Meter Calibration.....	201
Other Subpart P Comments	202

TABLE OF CONTENTS

<u>Section</u>	<u>Page</u>
8. SUBPART V - NITRIC ACID PRODUCTION.....	203
9. SUBPART X: PETROCHEMICAL PRODUCTION	203
GHGS to Report.....	203
Calculating CH ₄ and N ₂ O emissions for Ethylene Only Options	205
Equation X-1	205
Monitoring and QA/QC Requirements.....	208
Data Reporting Requirements.....	215
Other Subpart X Comments.....	216
10. SUBPART Y- PETROLEUM REFINERIES	218
GHGs to report.....	218
Reporting Emissions From Flares.....	220
Sulfur Recovery: Sour Gas Sent Offsite	221
CO ₂ Emissions From Asphalt Blowing	222
Other Equations	223
Calculating GHG Emissions	225
Monitoring and QA/QC Requirements.....	227
Other Subpart Y Comments.....	230
11. SUBPART AA - PULP AND PAPER MANUFACTURING.....	235
12. SUBPART NN - SUPPLIERS OF NATURAL GAS AND NATURAL GAS LIQUIDS	235
13. SUBPART OO - SUPPLIERS OF INDUSTRIAL GREENHOUSE GASES	235
Monitoring and QA/QC Requirements.....	235
Definitions.....	238
Other Subpart OO Comments.....	238
14. SUBPART PP - SUPPLIERS OF CARBON DIOXIDE	240
Calculating CO ₂ Supply	240
Equation PP-1	240
Equation PP-2	240
Other Subpart PP Comments	245
15. COMMENTS ON ADMINISTRATIVE PROCEDURES (E.G., COMMENT PERIOD)	246
16. COMMENTS ON LEGAL AUTHORITY FOR THE AMENDMENTS.....	247
17. GENERAL SUPPORT AND OPPOSITION FOR THE AMENDMENTS	248
General Support for the Amendments	248
General Opposition To The Amendments	250
18. COMMENTS ON PART 98 ISSUES THAT WERE COVERED BY THE FIRST PART 98 CORRECTIONS NOTICE	252
19. GENERAL OUT OF SCOPE COMMENTS	254

1. HOW THESE AMENDMENTS APPLY TO 2011 GHG EMISSION REPORTS

Commenter Name: Lorraine Krupa Gershman

Commenter Affiliation: American Chemistry Council

Document Control Number: EPA-HQ-OAR-2008-0508-2368.1

Comment Excerpt Number: 7

Comment: EPA required that sources have GHG Monitoring Plans in place by March 31, 2010. Many of these revisions will need to be incorporated into the existing plans, including: (1) Documenting the method(s) used to determine the HHV for Tier 2 fuels; (2) Documenting the method(s) used to calibrate Tier 3 fuel flow meters; (3) Documenting the method(s) used to determine the carbon content and molecular weight of Tier 3 gas fuels; and, (4) Preparing a monitoring plan for a new Tier 1 fuel due to the addition of “Fuel Gas” to Table C-1. EPA should provide additional time, until at least March 31, 2011, for the owner/operators to revise the GHG Monitoring Plan upon the finalization of these proposed MRR revisions.

Response: It is not necessary to impose a specific deadline, for example March 31, 2011, to revise the GHG Monitoring Plan to reflect the amendments to the GHG Reporting Rule because 40 CFR 98.3(g)(5)(iii) of the 2009 final rule already has a requirement to revise the GHG Monitoring Plan, as needed, to reflect changes in production processes, monitoring instrumentation, and quality assurance procedures, among other process changes. We do not see any unique circumstances that would necessitate applying a specific date by which these amendments need to be reflected in the monitoring plan. We would refer to the 2009 final preamble (74 FR 56281), which states, “Reporters need their monitoring plan to be up to date in order to ensure that facility or supplier personnel follow the right monitoring and QA procedures and that the reporter meets the requirements of the reporting rule. Likewise, EPA needs to be able to view an up-to-date monitoring plan during facility audits.”

Commenter Name: Jeff Applekamp

Commenter Affiliation: Gas Processors Association (GPA)

Document Control Number: EPA-HQ-OAR-2008-0508-2402.1

Comment Excerpt Number: 1

Comment: EPA seeks comment on the conclusion that it is appropriate to implement these amendments and incorporate the requirements in the data reported to EPA by March 31, 2011. Further, EPA seeks comment on whether there are specific subparts of Part 98 for which this timeline may not be feasible or appropriate due to the nature of the proposed changes or the way in which data have been collected thus far in 2010.

Given the nature of these amendments and objections [August 19, 2010 letter from the Clean Air Task Force, Natural Resources Defense Council, and Sierra Club.] raised to some of the amendments that result from the proposed GHGRP settlement agreements from 75 FR 42085 (July 20, 2010), companies do not know what the final amendments will contain, and thus can not take action to implement the provisions until the final rule is published.

Companies impacted by the GHGRP are currently nine months into the reporting period, with reporting required by March 31, 2011. Companies have been preparing for reporting under the GHGRP since the initial rule was proposed in April 2009. Currently GPA member companies are working toward meeting the original GHGRP requirements, while simultaneously attempting to understand the requirements for Confidential Business Information, EPA's reporting tool schema, and preparing for requirements proposed under Subpart W. It may not be feasible to incorporate revisions that impact emission calculations or reporting requirements this late in the reporting year. As discussed below, the proposed amendments to the natural gas definition could require data collection or equipment installation retroactive to January 1, 2010. In addition, reconfiguring and retesting software or other calculation tools takes time.

For the 2010 reporting year, GPA requests that EPA provide companies with the option of reporting based on the requirements from the October 30, 2009 version of the rule or based on the amended requirements when they are published as final.

Response: EPA disagrees with the commenter and is requiring the final amendments to be reflected in the first reports submitted to EPA by March 31, 2010. We appreciate the commenter providing a specific example of where the proposed amendments would not be feasible to implement for these first reports. Specifically, with respect to the concern about the definition of natural gas, we have finalized a definition that does not include specific specifications for Btu value and methane content for natural gas. As pointed out by several commenters, these change in definition could have resulted in some units being subject to a higher calculation tier under subpart C (e.g., Tier 3 versus Tier 2) than they originally expected in early 2010. Please see Section II.F of the Preamble for EPA's rationale for the final definition of natural gas. As described in Section I.D of the preamble to the final rule amendments we have concluded that the amendments as finalized can be implemented for the 2010 reporting year.

We recognize that EPA has published several proposed rulemakings, as well as some final rulemakings related to the GHG Reporting Program in 2010. EPA does not agree that the rulemaking and other activities undertaken by EPA and mentioned by the commenter should impact the ability of the commenter to incorporate the amendments into the first reports on March 31, 2011. As described in Section I.E of the preamble, in general, the specific amendments finalized should ease burden and in many cases, the requirement of the 2009 final rule is retained as an option. The other rulemaking activities mentioned by the commenter are independent from this final rule and do not have a substantive impact on the emissions calculation requirements for the subparts included in this rulemaking. Therefore we have determined that the fact that there are multiple rulemakings does not provide a sufficient rationale for delaying this rulemaking or allowing reporters the option of following the 2009 final rule, or the rule as amended here, in the first annual report.

Commenter Name: Bryan Brendle
Commenter Affiliation: Portland Cement Association
Document Control Number: EPA-HQ-OAR-2008-0508-2399.1
Comment Excerpt Number: 1

Comment: Because the agency has opened this “final” rule to further revision on multiple occasions, including the CBI issue, PCA recommends acceptance of the first reports through June 30, 2011.

Among other provisions, EPA is requesting comment on proposed amendments to Subpart A and Subpart C of the MRR. Whereas Subpart A addresses reporting of biogenic emissions, Subpart C focuses on stationary fuel combustion and will be relevant to all cement manufacturers preparing reports for 2010 emissions. As a general matter, EPA states that the proposed amendments to Subpart C would not require monitoring or information collection above what is already required by Part 98. Therefore, EPA expects that sources will be able to use the same information that they have been collecting under Part 98 to calculate and report GHG emissions for 2010. As stated in PCA comments on the June 15 proposal, modification of Subpart C focusing on stationary fuel combustion will have a major impact on the cement industry.

Response: EPA disagrees with the commenter and is requiring the final amendments to be reflected in the first reports submitted to EPA by March 31, 2010. The proposed rulemaking was not soliciting comment on the other activities related to the Greenhouse Gas Reporting Program (GHGRP), including the proposed rulemaking “Confidentiality Determination for the Mandatory Greenhouse Gas Reporting Rule and Proposed Rule Amendment Specifying Procedures for Handling Part 98 Data,” mentioned by the commenter. PCA does not provide specific comments on why they cannot implement the proposed amendments in the August 11, 2010 proposal, rather, in general, they merely allege that modifications to subpart C will have a major impact on the cement industry. Please see response to comment EPA-HQ-OAR-2008-0508-2402.1, excerpt 1 and Section I.D of the preamble to the final rule amendments for the response to this comment.

Commenter Name: Brian Gasiorowski
Commenter Affiliation: Lafarge North America
Document Control Number: EPA-HQ-OAR-2008-0508-2401.1
Comment Excerpt Number: 5

Comment: Due Date for Initial Annual GHG Emission Report. EPA requested comment on its conclusion that all of the technical amendments and corrections can be implemented and incorporated into the initial GHG emissions reports by the due date of March 31, 2011. Specifically, EPA asked for comments on whether this timeline is feasible or appropriate, considering the nature of the proposed changes and the way in which data have been collected thus far in 2010.

Lafarge believes the deadline for the initial annual report should be extended to June 30, 2011. It's important to note that the extra time will be needed since facilities have been collecting data and performing calculations on a monthly basis throughout 2010. This has been a particularly labor- and data-intensive program for the many cement plants, particularly those that will not begin using CO₂ CEMs until either late in 2010, or by January 1, 2011. While it's recognized the proposed rule changes are intended to simplify, the fact remains that it will take a great deal of extra work to reconcile any differences between the data collection and calculation approach actually used in 2010 (up to this point) with the changes that are ultimately finalized by EPA. This extra work will be necessary in order to ensure both data accuracy and full compliance with the proposed amendments which EPA is intending to make retroactively effective for all of 2010.

Arising from the technical amendments and corrections, there will be extensive internal QA/QC required to validate whether proper changes have been made to spreadsheets and data elements used for emissions calculations at each plant. This labor-intensive effort justifies and extensive of the deadline for submitting the initial annual GHG reports to June 30, 2011.

Response: Please see response to comment EPA-HQ-OAR-2008-0508-2399.1, excerpt 1. We recognize that there will be some additional costs associated with reviewing the regulation and determining how it applies to your facility. For a discussion of the estimated burden associated with today's final rule, please refer to the economics discussion in "Final Part 98 Economics Memo for Revisions Rulemaking" that has been placed in docket EPA-HQ-OAR-2008-0508 for the final rule.

Commenter Name: Robert Rouse
Commenter Affiliation: The Dow Chemical Company
Document Control Number: EPA-HQ-OAR-2008-0508-2366.1
Comment Excerpt Number: 5

Comment: The proposed addition of "Fuel Gas" to Table C-1 of the Reporting Rule has additional impacts on the implementation of this rule that EPA should account for as detailed below.

Fuels used in combustion units with a heat input < 250 MMBtu/hr were previously not subject to the reporting rule if the fuel was not listed in Table C-1. The proposed rule will result in numerous fuel streams now becoming subject to the requirements as Tier 1 fuels. As a result of this proposal, the owner/operator will be required to re-assess all previously exempt streams, develop monitoring plan documents, and train additional site personnel on these requirements of the reporting rule. Therefore, additional time will be needed to implement these changes.

EPA should provide owner/operators the option to use the new reporting provisions in the report due March 31, 2011, but not mandate the use of the new requirements until the Year 2011 report which is due by March 31, 2012.

Response: We appreciate the commenter providing a specific example of where the proposed amendments would not be feasible to implement for these first reports. However, with respect to

the concern about the addition of fuel gas to Table C-1, EPA did not intend for this amendment to require additional fuels to be covered under the GHGRP. In the final rule, EPA has modified the definition of “fuel gas” to limit the applicability of this term, thereby removing the reason for the extension requested by the commenter. Please see response to comment, EPA-HQ-OAR-2008-0508-2366.1, excerpt 4 for the rationale for this amendment in the final. As described in Section I.D of the preamble to the final rule amendments we have concluded that the amendments can be implemented for the 2010 reporting year.

Commenter Name: Robert Rouse

Commenter Affiliation: The Dow Chemical Company

Document Control Number: EPA-HQ-OAR-2008-0508-2366.1

Comment Excerpt Number: 6

Comment: EPA Should Provide Additional Time for Owner/Operators to Update GHG Monitoring Plans.

Throughout the proposed rule, EPA proposes several items that clarify what information should be included in the GHG Monitoring Plan. Source owners were required to have GHG Monitoring Plans in place by March 31, 2010, thus these changes will require review and editing of these plans in order to add the additional items. In addition, some sources may need GHG Monitoring Plans developed for the first time due to the addition of "Fuel Gas" to Table C-1. Therefore, EPA should provide additional time, until at least March 31, 2011, for the source owners to update the content of the GHG monitoring plans or prepare new plans.

Some examples of additional monitoring plan requirements are:

- Documenting the method(s) used to determine the HHV for Tier 2 fuels.
- Documenting the method(s) used to calibrate Tier 3 fuel flow meters,
- Documenting the method(s) used to determine the carbon content and molecular weight of Tier 3 gas fuels.
- Preparing a monitoring plan for a new Tier 1 fuel due to the addition of "Fuel Gas" to Table C-1.

Taken collectively, source owners will need additional time to update existing monitoring plans and to create new monitoring plans.

Response: The requirements from the 2009 final rule in §98.3(g)(5)(i) have always required the GHG Monitoring Plan to contain an explanation of the processes and methods used to collect the necessary data for the GHG calculations. Although this final rulemaking is more explicit in certain cases, pointing out that a method should be documented in the monitoring plan this is simply a clarification and not a new requirement. Regarding the concern about fuel gas, EPA has modified the definition of “fuel gas” in the final rule to limit the applicability of this term. Please see response to comment EPA-HQ-OAR-2008-0508-2366.1, excerpt 4 for a discussion of this amendment.

Please see response to comment EPA-HQ-OAR-2008-0508-2368.1, excerpt 7, regarding the comment about updating the GHG Monitoring Plan.

Commenter Name: Lauren E. Freeman

Commenter Affiliation: Utility Air Regulatory Group (UARG)

Document Control Number: EPA-HQ-OAR-2008-0508-2388.1

Comment Excerpt Number: 13

Comment: Application of Revised Rules to 2011 Reports.

UARG agrees that reporters should be allowed to use the revised rules in their 2011 reports of 2010 emissions. Requiring facilities to report under the existing rules when EPA has determined that those rule are overly burdensome or unclear is not reasonable. However, UARG is concerned that there may be instances where the revised rules could be construed as limiting (not expanding) the options for calculating emissions. For example, consistent with the UARG settlement, EPA proposes to revise § 98.33(a)(2)(ii) to require calculation of weighted HHV “only for individual Tier 2 units with a maximum rated heat input capacity greater than or equal to 100 mmBtu/hr, and for groups of units that contain at least one unit of that size.” (75 FR 48756.) For smaller units, the annual arithmetic average HHV would be used instead. See supra at section V. Because the rule currently provides no exception to the HHV weighting requirement for small units, facilities with combustion sources affected by that provision have been retaining the information necessary to determine monthly fuel use and apply the HHV weighing required in the rule in the event EPA does not revise the rule. Because the work has already been done, those facilities should not be prevented from reporting data using those procedures in 2010. Although UARG has not identified any other examples, others might exist. To avoid unintended results, UARG requests that EPA not prohibit use of any current provision for 2010 emissions reporting, unless EPA can identify a significant discrepancy between the existing provision and the reporting requirements in the final rule.

Response: EPA disagrees with the commenter and is requiring the final amendments to be reflected in the first reports submitted to EPA by March 31, 2010. We appreciate the commenter providing a specific example of where the proposed amendments would not be feasible to implement for these first reports. Specifically, with respect to the concern about the calculation of HHV for Tier 2 units with a maximum rated heat input capacity less than 100 mmBtu/hr. EPA has finalized the rule to allow these units to use either a weighted HHV calculation or the annual arithmetic average, thereby retaining as an option the requirement from the 2009 final rule. Please see response to comment, EPA-HQ-OAR-2008-0508-2371.1, excerpt 6 for the rationale for this amendment in the final. As described in Section I.D of the preamble to the final rule amendments we have concluded that the amendments can be implemented for the 2010 reporting year.

Commenter Name: Bryan Brendle

Commenter Affiliation: Portland Cement Association

Document Control Number: EPA-HQ-OAR-2008-0508-2399.1

Comment Excerpt Number: 15

Comment: Per comments submitted with respect to EPA's proposed amendments published on June 15, PCA recommends extension of due dates for the initial reports to June 30, 2011 for the 2010 GHG data only. Subsequent reports would be due on March 31 of each calendar year, beginning in 2011. Modification of Subpart C for stationary combustion will have significant impacts on the cement industry, influencing the ability to file accurate reports. The extra time will be needed since plants have been collecting data and performing calculation on a monthly basis throughout 2010. This has been particularly labor-intensive especially for plants that will not begin using CO₂ CEMS until either late in 2010, or by January 1, 2011. The proposed rule changes may be intended to simplify, but the fact is it will take a great deal of extra work to rectify any differences between the data collection and calculation approach actually used in 2010 with changes finalized by EPA. This extra work will be necessary in order to ensure compliance with the proposed amendments which EPA is intending to make retroactively effective for all of 2010. There will be extensive internal QA/QC required to validate whether correct changes have been made to spreadsheets and data elements used for each emission source at each plant.

Response: Please see response to comment EPA-HQ-OAR-2008-0508-2399.1, excerpt 1.

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2008-0508-2383.1

Comment Excerpt Number: 16

Comment: API believes any revision that requires new measurement or recordkeeping will have difficulty meeting the March 31, 2011 reporting deadline if data collection, sampling, or record requirements are retroactive to January 1, 2010. Examples include, fuel gas streams combusted at petrochemical facilities that were previously exempt from Tier 3 requirements, small metered off-gas or vent gas streams at refineries that were previously exempt from Tier 3 requirements, and exhaust flow gas meters required under 98.254(f) to comply with Refinery MACT requirements.

Response: EPA disagrees with the commenter and is requiring the final amendments to be reflected in the first reports submitted to EPA by March 31, 2010. We appreciate the commenter providing specific examples of where the proposed amendments would not be feasible to implement for these first reports. Specifically, with respect to the concern about the fuel gas streams, we have modified the definition of fuel gas in this final rule with a goal to not subject additional fuels to reporting that would not have otherwise been required to be reported according to the 2009 final rule. For a further discussion of the rationale for the change in the definition of fuel gas, please refer to section II.G of the preamble.

Regarding the concern that there are fuel gas streams that "were previously exempt" from reporting but now would have to be measured, EPA disagrees with the commenter's concerns. The proposed amendments on August 11, 2010 specifically proposed relief in 98.243(d)

“Optional combustion methodology for ethylene production processes”. The 2009 final rule was clear that these streams must be measured using Tier 3 or Tier 4. The final amendments, as proposed, allow use of Tier 1 or Tier 2 under certain conditions. The proposed rule did not impose Tier 3 on new streams, therefore we have determined that the request to extend implementation for measuring these streams is not warranted.

Finally, with respect to the concern about requiring exhaust flow gas meters required under 98.254(f) to comply with Refinery MACT requirements, we agree with the commenter that it is inappropriate to add these requirements to process vent flow meters at this juncture, thus this concern does not justify an extension. For a further discussion of the rationale for these final rule requirements, please refer to section II.N of the preamble to the final rule.

Based on the discussion above, we have concluded that there is no need to postpone implementation of these amendments and, as described in Section I.D of the preamble to the final rule amendments we have concluded that the amendments can be implemented for the 2010 reporting year.

2. SUBPART A – GENERAL PROVISIONS

Applicability threshold for natural gas LDCs

Commenter Name: Bert Kalisch

Commenter Affiliation: American Public Gas Association (APGA)

Document Control Number: EPA-HQ-OAR-2008-0508-2355

Comment Excerpt Number: 1

Comment: APGA supports applying the 25,000 metric ton threshold to local gas distribution systems. APGA supports the 25,000 metric ton CO₂ equivalent threshold, because application of the threshold would appropriately eliminate unduly burdensome requirements. We believe that changes proposed in this proposed rule by EPA adequately address APGA’s concerns. APGA also agrees with EPA’s decision to express the reporting limit in cubic feet rather than metric tons of CO₂; it will be much easier for LDCs to determine if they are over the reporting threshold. Owners and operators of LDCs know how much natural gas they deliver to their customers and it would, therefore, be easier for facilities to determine if they are subject to the rule than if the threshold were specified in metric tons of CO₂.

Response: We thank the commenter for the input. We have finalized the proposed requirements to amend the threshold for local distribution companies to 460,000 thousand standard cubic feet or more of natural gas delivered per year. This level is approximately equivalent to 25,000 mtCO₂e per year. Please see Section II.P in the preamble to the final rule

amendments, as well as Section II.P of the proposal preamble (75 FR 48776) for additional information.

Commenter Name: Bert Kalisch

Commenter Affiliation: American Public Gas Association (APGA)

Document Control Number: EPA-HQ-OAR-2008-0508-2355

Comment Excerpt Number: 2

Comment: REQUESTED CLARIFICATION. APGA supports the fundamental approach of the proposed rule. However, APGA believes that the EPA should provide the following clarification: The reporting threshold for local gas distributors in amended Section 98.2(a) (4)(iii)(B) is expressed in cubic feet of natural gas, but in several other sections of the rule thresholds continue to be expressed only in metric tons CO₂ equivalent. Specifically, Sections 98.2(i)(1) and (2) allow entities to stop reporting if emissions are less than 25,000 metric tons for 5 consecutive years or less than 15,000 metric tons for 3 consecutive years. 25,000 metric tons is approximately 460 million cubic feet of natural gas and 15,000 metric tons is approximately 276 million cubic feet of natural gas. APGA urges EPA to clarify that the threshold for natural gas distributors (460,000 thousand cubic feet per year) is equivalent to the threshold of 25,000 metric tons CO₂ wherever that metric ton threshold appears in the rule. In particular, EPA should clarify that the conditions for ceasing reporting to EPA listed in Sections 98.2(i)(1) apply to LDCs if an LDC supplies less than 460 million cubic feet of gas for 5 consecutive years and that Section 98.2(i)(2) applies if an LDC delivers less than 276 million cubic feet or gas for 3 consecutive years. APGA believes this is consistent with the intent of these two sections.

Response: See section II.P in the preamble to the final rule amendments for the response to this comment.

Commenter Name: Pamela A. Lacey

Commenter Affiliation: American Gas Association

Document Control Number: EPA-HQ-OAR-2008-0508-2394.1

Comment Excerpt Number: 1

Comment: The American Gas Association (AGA) supports applying the 25,000 metric ton threshold to local gas distribution systems. AGA supports EPA's proposal to exempt small natural gas local distribution companies (LDCs) that deliver less than 460,000 thousand standard cubic feet of natural gas per year from the reporting and other requirements under Subpart NN of the MRR. In addition, AGA supports comments filed in this docket by the American Public Gas Association (APGA) requesting EPA to clarify that the reporting threshold for natural gas LDCs (460,000 thousand standard cubic feet per year) is equivalent to the threshold of 25,000 metric tons CO₂ wherever that metric ton threshold appears in the rule. We agree with APGA that EPA should clarify that the conditions for being allowed to cease reporting to EPA listed in Section 98.2(i)(1) should apply to an LDC if it supplies less than 460,000 thousand standard cubic feet per year for 5 consecutive years and that section 98.2(i)(2) applies if an LDC delivers less than 276,000 thousand cubic feet of natural gas for 3 consecutive years. It makes no sense to impose

the numerous reporting and recordkeeping burdens of Subpart NN on these small LDCs, when they represent less than 1 percent of the reported GHG emissions associated with LDC supply – a much lower percent than the 10 to 15 percent of GHG emissions that are excluded in other sectors by the comparable 25,000 ton per year (tpy) carbon dioxide equivalent (CO₂e) threshold used in other Subparts of the MRR. See 75 Fed. Reg. at 48776.

Response: Please see response to comment EPA-HQ-OAR-2008-0508-2355.1, excerpt 2.

Commenter Name: Ann W. McIver
Commenter Affiliation: Citizens Energy Group
Document Control Number: EPA-HQ-OAR-2008-0508-2387.1
Comment Excerpt Number: 1

Comment: Citizens supports the proposed changes in applicability at 40 CFR 98.2(a) to exempt natural gas LDCs that distribute less than 460,000 mscf to customers per year from the annual GHG reporting requirements. This exemption will remove an administrative burden from these small natural gas LDCs.

Response: EPA thanks the commenter for the input. We have finalized the proposed requirements to amend the threshold for local distribution companies to 460,000 thousand standard cubic feet or more of natural gas per delivered per year. Please see Section II.P, in the preamble to the final rule amendments as well as Section II. P of the proposal preamble (75 FR 48776) for additional information.

Commenter Name: Helen D. Silver
Commenter Affiliation: Clean Air Task Force et. al
Document Control Number: EPA-HQ-OAR-2008-0508-2403.2
Comment Excerpt Number: 12

Commenter Name: Craig Holt Segall
Commenter Affiliation: Sierra Club Environmental Law Program et. al
Document Control Number: EPA-HQ-OAR-2008-0508-2398.3
Comment Excerpt Number: 12

These two commenters submitted identical comments on this subject.

Comment: EPA proposes to exempt local natural gas distribution companies (“LDCs”) delivering 460,000 thousand cubic feet or less per year from all reporting requirements. See 75 Fed. Reg. at 48,777. EPA had previously included all LDCs in the rule, and “did not receive any comments opposed to the ‘all in’ designation,” while it did receive two supportive comments. Id. Because LDC owners and operators “know how much natural gas they deliver,” reporting is not particularly burdensome. Id. We are therefore skeptical of EPA’s decision to exempt these sources now.

EPA concludes that exempting smaller LDCs would diminish “emissions coverage [by] . . . less than 1 percent.” Id. EPA should clarify whether this is a loss of 1 percent in this specific category or across the entire rule. If it is the latter, we strongly oppose the exemption, as 1% of national emissions is quite significant. Either way, we ask that EPA provide lost coverage estimates in both tons and percentages, as this makes it easier to assess. If the loss is large, EPA should reconsider the exemption, as reporters face a low burden here, and did not oppose their inclusion during the public comment period.

Response: No rule change has been made as a result of this comment. Please see section II.P of the proposal preamble (40 CFR 48744) for a discussion regarding EPA’s rationale for amending the threshold for LDCs. We considered the burden associated with reporting, the quantities of greenhouse gases that will be reported by these smaller LDCs, as well as the fact that after five years all of these LDCs would no longer be required to report per the off-ramp clause in 98.2(i) (many would no longer be required to report after three years per this provision).

In exhibit 7 of the technical supporting document for suppliers of natural gas and natural gas liquids from January 28, 2009, EPA displays the emissions coverage that would be attained at various reporting thresholds for local natural gas distribution companies. According to that estimate, having a reporting threshold of 25,000 mtCO₂e (approximately equivalent to 460,000 mscf of natural gas) for LDCs would still cover 99.28% of emissions associated with all natural gas delivered by LDCs. The lost coverage of 0.72% from LDCs equates to approximately 4,500,000 mtCO₂e, which is less than 0.1% of total emissions in the United States per year.

EPA has concluded that this loss in emissions coverage is small enough to justify the change in reporting threshold.

Content of annual report- separate biogenic CO₂ emissions reporting

Commenter Name: Kerry Kelly

Commenter Affiliation: Waste Management (WM)

Document Control Number: EPA-HQ-OAR-2008-0508-2360.1

Comment Excerpt Number: 8

Comment: EPA has proposed changes to Section 98.3(c)(4) Content of the annual report, with the stated intent of clarifying that units subject to subpart D or other Part 75 units are not required to separately report their biogenic CO₂ emissions, but may do so optionally. However, the proposed amendments to Section 98.3(c)(4) go far beyond the Agency’s stated intent and will adversely affect the quality and transparency of reporting for many more types of facilities.

The proposed revisions to 40 CFR 98.3(c)(4)(i) would require all reporters to report annual, aggregated, facility-wide anthropogenic and biogenic emissions. However, this does not appear to be the actual intent of the revision, as the preamble to the proposed changes at section II. C. states:

We intended for the reporting of biogenic CO₂ emissions to be optional for units subject to subpart D. However, the current rule does not consistently affirm this. To address these concerns, we are proposing to amend the data elements in subparts A and C that currently require separate accounting and reporting of biogenic CO₂ emissions so that it would be optional for Part 75 units.”

The revisions as proposed will result in less clear and complete emissions reporting information for the public, EPA and state regulators as there will be no delineation of the biogenic emissions versus anthropogenic emissions of a facility. WM has many facilities reporting under subpart HH and subpart C. For these facilities fully half to all of the total GHG emissions are biogenic. We do not feel it is appropriate to force us to aggregate these emissions with our anthropogenic GHG emissions.

Emissions reporting will be more accurate, more transparent and complete if our biogenic and anthropogenic emissions are separately reported as now required in the Final Rule. This is particularly important as EPA has just requested comments on the treatment of biogenic emissions in implementing the Tailoring Rule. Distinct reporting of anthropogenic versus biogenic emissions will be necessary to support EPA’s ultimate decision.

We recommend that EPA amend 40 CFR 98.3(c)(4)(i) as follows so as to maintain the delineated anthropogenic and biogenic emissions reporting while allowing subpart D reporters and Part 75 methodology users to optionally report biogenic CO₂ emissions:

Annual emissions (excluding biogenic CO₂) aggregated for all GHG from all applicable source categories in subparts C through JJ of this part and expressed in metric tons of CO₂e calculated using Equation A-1 of this subpart, with the exception of sources subject to subpart D or sources using Part 75 methodologies to calculate CO₂ mass emissions, which are not required to exclude biogenic emissions from the annual emissions. EPA’s proposed changes to 40 CFR 98.3(c) (ii) and (c) (4) (iii) (A) to clarify that subpart D reporters or units using Part 75 methodologies to calculate CO₂ mass emissions need only report biogenic CO₂ optionally can remain the same as proposed.

Further, WM recommends that the Agency commit to making optionally reported biogenic CO₂ emissions information readily and transparently available to the public and to state regulators.

Response: Please see Section II.C in the preamble to the final rule amendments for the response to this comment.

The recommendation to make biogenic CO₂ emissions readily available is beyond the scope of the amendments proposed on August 11, 2010. On July 7, 2010 we published a proposed regulation in the *Federal Register* with our proposed determination regarding the confidential nature for each data element under the Greenhouse Gas Reporting Program. The comment period closed on September 7, 2010. We are still reviewing comments submitted on that proposal.

Commenter Name: Eldon Lindt
Commenter Affiliation: Xcel Energy Inc.
Document Control Number: EPA-HQ-OAR-2008-0508-2374.1
Comment Excerpt Number: 1

Comment: The Mandatory Reporting of Greenhouse Gases final rule (hereinafter "final rule") does not provide clear guidance on biogenic reporting requirements for Subpart D, nor for units using other Part 75 methodologies to report emissions. The proposed rule clarifies that separate reporting of biogenic emissions for these units is optional. Xcel Energy supports this clarification because it is consistent with existing 40 CFR Part 75 practices, which allow aggregated reporting of non-biogenic and biogenic emissions.

Response: Please see Section II.C in the preamble to the final rule amendments for the response to this comment.

Commenter Name: Stephen E. Woock
Commenter Affiliation: Weyerhaeuser Company
Document Control Number: EPA-HQ-OAR-2008-0508-2375.1
Comment Excerpt Number: 1

Comment: Biogenic CO₂ reporting should not be revised as EPA proposed –but EPA can ease separate reporting of biogenic and fossil fuel emissions for CEMS users. Proposed revisions in several provisions of Subpart A and Subpart C would allow 40 CFR Part 75 methods users to report biogenic CO₂ separately on a voluntary basis, and, unlike the current final regulation, all GHG emissions reporters would be directed to first report their total GHG emissions including biogenic CO₂. For example, see proposed rule language at §98.3(c)(4)(i), which substitutes “including” for “excluding” with respect to reporting biogenic CO₂ emissions. This has the effect of lumping biogenic CO₂ emissions with fossil GHG emissions instead of the totally separate reporting of those emissions promulgated in the final rule. After reporting co-mingled fossil and biogenic GHG emissions, only the reporters not using Part 75 methods would still be required to report biogenic CO₂ as a separate line item.

These proposed changes are the result of a proposed settlement agreement between EPA and UARG and are principally aimed at electric utility generating units subject to 40 CFR §98 Subpart D, that is, sources that are subject to the Acid Rain Program and are using continuous emissions monitoring systems (CEMS) to measure the total CO₂ existing their exhaust stacks. See footnote 1. However, the proposed subsequent proposed revisions to the GHG MRR upon which we are commenting raise this reporting issue in the context of trying to resolve UARG members’ concerns regarding the substantial and burdensome fossil fuel analyses and additional work beyond what Part 75 already requires. The additional work occurs since CO₂ CEMS measurements alone do not differentiate among the sources of the CO₂. Specifically, the existing requirement to determine and report separately a small fraction of CO₂ that is biogenic in origin amidst the predominant use of fossil fuel at an electric utility plant using CO₂ CEMS and reporting using Part 75 methods appears unreasonable. However, instead of making the separate reporting of biogenic CO₂ more manageable for UARG members, EPA provides a proposed

solution --an exemption from reporting biogenic CO₂ and a change in the reporting focus-- that we believe is problematic. [Footnote: We provide six examples of problems arising in our comments on the settlement agreement. See Exhibit 1 in DCN: EPA-HQ-OAR-2008-0508-2375.1.]

As we noted in our comments on the proposed settlement agreement, we believe as a first principle that separate reporting of biogenic CO₂ should be mandatory for all source categories subject to EPA's GHG MRR. It should not be optional, as suggested in the proposed settlement agreement with UARG and as configured in the proposed revisions in Subpart A and Subpart C. We believe separate reporting of biogenic CO₂ is important because it is consistent with the approach taken in the IPCC and national and regional U.S. GHG inventory frameworks, and it correctly supports the concept that biogenic CO₂ emissions in the U.S. are carbon neutral. This is because CO₂ is captured from the atmosphere in the photosynthetic process, therefore the biogenic CO₂ released to the atmosphere during biomass combustion is a net neutral and the CO₂ does not contribute to the overall global GHG inventory. Also, the separate reporting of biogenic CO₂ is appropriate for transparency and inventory balancing purposes since biogenic CO₂ is accounted for in the land use portions of the EPA National Inventory. These concepts are explained in great detail in Weyerhaeuser's comments [Footnote: Weyerhaeuser's comments on the "Call for Information" are assigned Docket ID No. EPA-HQ-OAR-2010-0560-0563.1.] filed recently in response to EPA's PSD Tailoring Rule "Call for Information."

We have already addressed this issue in detail in our comments on the settlement agreement and have proposed a reasonable solution therein to ease the UARG members' burden while retaining the completely separate reporting of biogenic CO₂ emissions already promulgated in the final GHG MRR. Because of that we will cut our comments short here and adopt those previous comments into this rulemaking as Exhibit 1. We urge EPA to adopt the alternative solution proposed in those earlier comments and preserve the appropriate reporting framework for biogenic CO₂ emissions that is embodied in the final GHG MRR issued October 30, 2009. While we believe our proposed alternative solution is reasonable and workable for all parties, we are open to other approaches that achieve the same necessary endpoints: the separate reporting of biogenic CO₂ (i.e., not comingled with fossil GHG emissions reporting totals) and mandatory reporting of biogenic CO₂ emissions for all subject to the GHG MRR. We stand ready to work with EPA, UARG and other parties to resolve this question.

Response: Please see Section II.C in the preamble to the final rule amendments for the response to this comment.

Commenter Name: Caitlin Post

Commenter Affiliation: Southern Company

Document Control Number: EPA-HQ-OAR-2008-0508-2377.1

Comment Excerpt Number: 1

Comment: EPA is proposing to make the separate reporting of biogenic emissions for units subject to subpart D optional. Southern Company understands that this option is beneficial for units that are burning small amounts of biomass and do not want the burden of separating out

these emissions since they are not currently required to do so per the requirements of Part 75. By incorporating this option into the rule, EPA had to change the requirement to report annual carbon dioxide (CO₂) emissions from each source category in subparts C through JJ of this part to include biogenic CO₂ emissions. Southern Company realizes this change is necessary to integrate this option into the rule. However, the Company suggests EPA allow optional reporting of annual CO₂ emissions excluding biogenic CO₂ emissions in addition to the annual CO₂ emissions including biogenic CO₂ emissions.

It is appropriate to allow units the option to report annual CO₂ emissions excluding biomass because the combustion of biomass causes no net increase in CO₂ on a lifecycle basis. CO₂ emissions from biomass combustion, in contrast to CO₂ emissions from fossil fuels which represent a one-way process (release of geologic carbon that has been out of the atmosphere for millions of years), are part of a two-way process – termed the biogenic carbon cycle. Plants absorb CO₂ as they grow and release it as they decay or are burned. This cycle releases no new CO₂ into the atmosphere, which is why this cycle is termed “carbon neutral.” Significantly, in many cases, the combustion of certain biomass fuels avoids methane emissions from biomass decay, generating a net effect that is better than carbon neutral. Ultimately, CO₂ emissions from biomass are different from CO₂ emissions from fossil fuels.

EPA already treats biogenic CO₂ emissions differently than other CO₂ emissions in the MRR by excluding biogenic CO₂ emissions in determining if a facility meets the applicability threshold. Also, EPA references this difference in its final Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule (Tailoring Rule). EPA states in the Tailoring Rule that: “We [EPA] are mindful of the role that biomass or biogenic fuels and feedstocks could play in reducing anthropogenic GHG emissions, and we do not dispute the commenters’ observations that many state, federal, and international rules and policies treat biogenic and fossil sources of CO₂ emissions differently.” Since releasing the Tailoring Rule, EPA, according to Executive Order 13514, collaborated with the Department of Energy, the Department of Defense, the General Services Administration, the Department of the Interior, the Department of Commerce and other agencies to develop draft Federal Greenhouse Gas Reporting and Accounting Guidance. This guidance exempts biogenic CO₂ emissions from Federal agency greenhouse gas reduction targets.

All units except those subject to subpart D must still report their biogenic CO₂ emissions separately. Therefore, it would not be burdensome to allow units the option to also report their annual CO₂ emissions excluding biomass. Units subject to subpart D that choose to not report their biogenic CO₂ emissions separately should not be required to report their annual CO₂ emissions excluding biomass.

Response: Please see Section II.C in the preamble to the final rule amendments for the response to this comment.

Commenter Name: Edward W. Repa

Commenter Affiliation: National Solid Wastes Management Association (NSWMA)

Document Control Number: EPA-HQ-OAR-2008-0508-2379.1

Comment Excerpt Number: 1

Comment: Section 98.3(c)(4)(ii) states: “Annual emissions of biogenic CO₂ aggregated for all applicable source categories in subparts C through JJ of this part in metric tons. Units that use the methodologies in part 75 of this chapter to calculate CO₂ mass emissions are not required to separately report biogenic CO₂ emissions, but may do so as an option.” Similar language is also contained in section 98.3(c)(4)(iii)A). EPA states in the preamble that the rationale for proposing this change is “to provide clarity and remove any potential inconsistencies” [C. Subpart A. (General Provisions): Reporting of Biogenic Emissions]. However, NSWMA believes the proposed changes are less clear and will only cause more inconsistencies because data users (e.g., federal and state regulators, the public) [who] will not be able to tell the difference between biogenic and anthropogenic emissions from a source.

NSWMA’s landfill members manage MSW that is comprised of more than 60 percent biomass, including paper and paperboard (31%), yard trimmings (13.2%), food scraps (12.7%), and wood (6.6%) (EPA 2009) [Footnote: 1 Beck, R.W. 2001. Size of the United States Solid Waste Industry. Environmental Research and Education Foundation. Alexandria, VA. 30 pp.]. This biomass is unique because it does not compete with other land uses for biomass production (e.g., good farmland is not being taken out of service). NSWMA believes that the mandatory reporting rule for GHG produced from biomass should not be accounted for in the same manner as anthropogenic GHG (e.g., fossil fuel use), which will allow emissions reporting to be accurate, transparent, comparative, and complete. In addition, the comment period on EPA’s Call for Information on Greenhouse Gas Emissions Associated With Bioenergy and Other Biogenic Sources (75 FR 41173) was just completed on September 13, 2010 and will determine how biogenic sources are treated under the EPA’s final rule Prevention of Significant Deterioration (PSD) and Title V Greenhouse Gas Tailoring Rule (Tailoring Rule). NSWMA suggests that EPA amend the language such that reporters submit separate biogenic and non-biogenic CO₂ aggregated for all GHG emissions from all applicable sources unless the source can justify in its report to EPA that this method is not possible.

Response: Please see Section II.C in the preamble to the final rule amendments for the response to this comment.

Commenter Name: Rhea Hale

Commenter Affiliation: American Forest & Paper Association (AF&PA)

Document Control Number: EPA-HQ-OAR-2008-0508-2382.1

Comment Excerpt Number: 1

Comment: The American Forest & Paper Association (AF&PA) objects to EPA’s proposal to combine reporting of biogenic and fossil fuel emissions. Rather, AF&PA offers an alternative proposal that would maintain the current requirement for separate reporting, thus insuring proper differentiation of fossil and biogenic emissions and accuracy of totals, while effectively eliminating the burden of separate reporting for subpart D sources utilizing Part 75 CO₂ CEMS.

Biogenic and fossil-based emissions are fundamentally different and should not be combined in one total. Climate change experts, including the IPCC and EPA, have always differentiated biomass-derived carbon from fossil-fuel derived carbon based on biomass's role in the global carbon cycle. Biomass-derived carbon is part of a relatively rapid natural cycle that, when in balance, neither adds nor subtracts carbon to/from the atmosphere, whereas fossil fuel-derived carbon is not part of such a rapid cycle and does add to the concentrations of GHG in the atmosphere. The carbon dioxide (CO₂) removed from the atmosphere during photosynthesis is converted into organic carbon and stored in biomass, such as trees and crops. When harvested and combusted, the carbon in the biomass is released as CO₂, thus completing the carbon cycle. The carbon in biomass will return to the atmosphere regardless of whether it is burned for energy or allowed to biodegrade. When we burn biomass for energy, we are simply inserting a step in the cycle that allows us to recover usable energy that can displace fossil fuels.

The carbon (CO₂) neutrality of biomass is universally accepted in greenhouse gas reduction programs as reflected in measurement protocols, legislative proposals, implemented regulations, voluntary programs, and in overall global strategies for greenhouse gas (GHG) reduction. EPA's proposed requirement for sources to combine fossil and biogenic emissions together in one total ignores the natural biomass carbon cycle, will overstate net CO₂ entering the atmosphere, runs counter to IPCC accounting protocols and will confuse established climate and renewable energy policy in this country.

EPA's proposal carries with it, whether intended or not, a distinct policy change implication with respect to biomass fuel. EPA's proposed approach cannot support future regulatory programs and will result in erroneous CO₂ totals for both fossil and biogenic emissions. The 1990 Clean Air Act Amendments require utility sources to monitor and report CO₂ emissions. In the past, EPA has not required Part 75 CEMs users to differentiate their fossil and biogenic carbon dioxide emissions. However, beginning in January 2011, EPA will begin regulating greenhouse gases beyond monitoring requirements for the first time. Therefore it will be necessary to maintain separate totals for fossil fuel-based emissions, which are measured at the point of combustion and biogenic emissions, which are measured most accurately as carbon stock changes on the land. Biogenic emissions at the point of combustion are often reported for informational purposes but do not represent a comprehensive accounting of biogenic emissions.

In addition, the Mandatory GHG Reporting Rule was authorized by Congress to support future climate change legislation. All proposed climate change legislation to date has emphatically excluded biogenic emissions from proposed caps, facility thresholds and reduction requirements. To support future legislative proposals it is imperative that separate totals are complete and accurate. By making separate reporting optional for Part 75 sources, EPA will be unable to determine an accurate accounting of fossil-based emissions or biogenic emissions as many sources will choose not to separate out emissions simply to reduce reporting burden, thus overstating the fossil total and understating the biogenic total.

Response: Please see Section II.C in the preamble to the final rule amendments for the response to this comment.

Commenter Name: Angela D. Marconi
Commenter Affiliation: Delaware Solid Waste Authority (DSWA)
Document Control Number: EPA-HQ-OAR-2008-0508-2392.1
Comment Excerpt Number: 1

Comment: Part 98.3(c)(4) contains revisions to the content of the annual report. These revisions apply to how biogenic emissions are to be reported. They include a requirement to report the total of biogenic and anthropogenic emissions together as well as reporting of biogenic emissions separately. Additionally, the reporters for subpart D are allowed the option of not reporting biogenic emissions separately. From examining the information sheet and section II.C of the preamble it appears that the revision does not accomplish what EPA intended it to. It appears that EPA's intent was to give reporters under subpart D the option of not separating their biogenic and anthropogenic emissions. DSWA request that EPA further revise this part to clarify its intent. DSWA is concerned that if left unchanged, the reporting of anthropogenic and biogenic emissions together will cause confusion for both reporters and the public and will make the information contained in the reports less transparent.

Response: Please see Section II.C in the preamble to the final rule amendments for the response to this comment.

Commenter Name: John H. Skinner
Commenter Affiliation: Solid Waste Association of North America (SWANA)
Document Control Number: EPA-HQ-OAR-2008-0508-2397.1
Comment Excerpt Number: 5

Comment: The Solid Waste Association of North America (SWANA) is concerned that this proposal would require aggregate reporting of carbon dioxide emissions. SWANA supports the separate reporting of biogenic and anthropogenic emissions, as was required in the final rule. This is particularly important as EPA has just requested comments on the treatment of biogenic emissions in implementing the Tailoring Rule. Distinct reporting of anthropogenic versus biogenic emissions will be necessary to support EPA's ultimate decision. A majority of the emissions from waste-to-energy operations are biogenic in nature and for more accurate reporting we believe it is necessary to report them separately.

Response: Please see Section II.C in the preamble to the final rule amendments for the response to this comment.

Commenter Name: Ted Michaels
Commenter Affiliation: Energy Recovery Council (ERC)
Document Control Number: EPA-HQ-OAR-2008-0508-2393.1
Comment Excerpt Number: 6

Comment: The proposed changes to biogenic emissions reporting are inconsistent with stated agency intent and will result in less transparent and complete reporting of GHG emissions. EPA has proposed changes to Section 98.3(c)(4) Content of the annual report, with the stated intent of

clarifying that units subject to subpart D or other Part 75 units are not required to separately report their biogenic CO₂ emissions, but may do so optionally. However, the proposed amendments to Section 98.3(c)(4) go far beyond the Agency's stated intent and will adversely affect the quality and transparency of reporting for many more types of facilities.

The proposed revisions to 40 CFR 98.3(c)(4)(i) would require all reporters to report annual, aggregated, facility-wide anthropogenic and biogenic emissions. However, this does not appear to be the actual intent of the revision, as the preamble to the proposed changes at section II. C. states: "We intended for the reporting of biogenic CO₂ emissions to be optional for units subject to subpart D. However, the current rule does not consistently affirm this. To address these concerns, we are proposing to amend the data elements in subparts A and C that currently require separate accounting and reporting of biogenic CO₂ emissions so that it would be optional for Part 75 units."

The revisions as proposed will result in less clear and complete emissions reporting information for the public, EPA, and state regulators as there will be no delineation of the biogenic emissions versus anthropogenic emissions of a facility. The large majority of GHG emissions from waste-to-energy facilities are biogenic, and it is inappropriate to force these facilities to aggregate these emissions with anthropogenic GHG emissions. Emissions reporting will be more accurate, more transparent and complete if our biogenic and anthropogenic emissions are separately reported as now required in the Final Rule. This is particularly important as EPA has just requested comments on the treatment of biogenic emissions in implementing the Tailoring Rule. Distinct reporting of anthropogenic versus biogenic emissions will be necessary to support EPA's ultimate decision.

We recommend that EPA amend 40 CFR 98.3(c)(4)(i) as follows (see the changes in square brackets) so as to maintain the delineated anthropogenic and biogenic emissions reporting while allowing subpart D reporters and Part 75 methodology users to optionally report biogenic CO₂ emissions: (i) Annual emissions ([excluding] biogenic CO₂) aggregated for all GHG from all applicable source categories in subparts C through JJ of this part and expressed in metric tons of CO₂e calculated using Equation A-1 of this subpart, [with the exception of sources subject to subpart D or sources using Part 75 methodologies to calculate CO₂ mass emissions.] EPA's proposed changes to 40 CFR 98.3(c)(ii) and (c)(4)(iii)(A) to clarify that subpart D reporters or units using Part 75 methodologies to calculate CO₂ mass emissions need only report biogenic CO₂ optionally can remain the same as proposed. Further, the Energy Recovery Council (ERC) recommends that the Agency commit to making optionally reported biogenic CO₂ emissions information readily and transparently available to the public and to state regulators.

Response: Please see Section II.C in the preamble to the final rule amendments for the response to this comment.

Commenter Name: Craig Holt Segall

Commenter Affiliation: Sierra Club Environmental Law Program et. al

Document Control Number: EPA-HQ-OAR-2008-0508-2398.1

Comment Excerpt Number: 8

Commenter Name: Helen D. Silver
Commenter Affiliation: Clean Air Task Force et. al
Document Control Number: EPA-HQ-OAR-2008-0508-2403.1
Comment Excerpt Number: 1

These two commenters submitted identical comments on this subject.

Comment: We strongly oppose EPA’s proposal to exempt subpart D and other source categories that comply with the monitoring and reporting requirements of the Acid Rain Program (“ARP”) from the requirement to report separately their biogenic CO₂ emissions. These facilities would include a large number of electricity generation facilities [See, e.g., 74 Fed. Reg. 56,260, 56,290 & 56,294 (Oct. 30, 2009)]. As discussed below, there is absolutely no valid justification – legal, scientific, or otherwise – for this exclusion.

Not surprisingly, EPA does not attempt to proffer one. Rather, EPA only states that it “intended” that subpart D source categories would continue to monitor and report as required by the ARP. Moreover – and most importantly – this exemption would severely undermine EPA’s execution of the sweeping congressional mandate that it require reporting from “all sectors of the economy.” See Appropriations Act of 2009, Pub. L. No. 110-329, 122 Stat. 3574-3716 (March 11, 2009), the purpose of which is to establish a comprehensive inventory of the sources of GHG emissions to inform the development of climate change policies.

As an initial matter, and as was noted in comments submitted by environmental organizations on proposed settlement agreements with respect to the MMR Rule, the monitoring and reporting requirements of the ARP do not and should not constrain EPA’s reporting requirements in the GHG context. Congress’s mandate to EPA is clear: to establish an economy-wide inventory of GHG emissions to inform climate policy. In contrast, the ARP was designed to prevent acid rain and not climate change. Therefore, very different considerations – including the GHG implications of different types of fuels – should govern EPA’s development of the congressionally mandated economy-wide GHG inventory. [Footnote: As was stated in comments on the proposed settlement agreements, it is not at all clear to us that the amount of biogenic CO₂ emissions can be back-calculated from data made publicly available under the ARP or what the burden would be on the public and policymakers to perform such a back-calculation, if it is in fact possible. Ex. 1 at 12-13.

Further review of the requirements of the ARP for this rulemaking has confirmed this. In fact, Appendix G of the ARP specifically states that when a unit combusts both fossil fuel and non-fossil fuels, the reporter should either use a CO₂ CEMS or apply to the Administration for approval of a unit specific method to determine CO₂ emissions. 40 C.F.R. Appx. G § 2. Nor is it clear to us that this information can be back-calculated based on the data reporting provisions of the MMR Rule, see 40 C.F.R. § 98.36(d), or pursuant to EPA’s proposed definition of “emission data,” 75 Fed. Reg. 39,094, 39,100-01.

However, even if this information can be back-calculated, the public interest overwhelmingly supports making this data available in the most transparent manner, particularly when such

calculations may be made in a straightforward manner by the polluter. Should EPA, however, finalize its proposal – which we would strongly oppose – EPA in the final rulemaking should clearly explain exactly how such back-calculations could be performed. In the past, EPA has correctly recognized that establishment of an accurate and comprehensive inventory, including the types of fuels used at facilities and related emissions, is fundamental to the development of effective climate change policies. The Agency has stressed that “[a]ccurate and timely information on GHG emissions is essential for informing many future climate change policy decisions” and that facility specific data is particularly important for understanding factors that influence GHG emissions rates and identifying actions and facilities that could reduce emissions [See 74 Fed. Reg. at 56,265]. Further, EPA has stated that “[b]esides total facility emissions, it benefits policy makers to understand: (1) The specific source of emissions and the amounts emitted by each unit/process to effectively interpret the data and (2) the effect of different processes, fuels, and feedstocks on emissions.” We agree. However, EPA’s proposal to exclude subpart D source categories from separately reporting biogenic CO₂ emissions would do serious damage to EPA’s efforts to gain a better understanding of the sources of GHG emissions and ways in which emissions of these harmful air pollutants can be reduced.

Ample evidence demonstrates that biomass is not inherently “carbon neutral” and that uses of some types of biomass, as compared to fossil fuels, may actually lead to a net increase in GHG emissions. [See, e.g., Comments of the Clean Air Task Force, Conservation Law Foundation, Natural Resources Council of Maine, Natural Resources Defense Council, Sierra Club and Southern Environmental Law Center on Call for Information: Information on Greenhouse Gas Emissions Associated with Bioenergy and Other Biogenic Sources (75 Fed. Reg. 41,173 (July 15, 2010), 27, available at <http://www.regulations.gov/search/Regs/home.html#home> (Docket ID. No. EPA-HQ-OAR-2010-0560) (Ex. 4). The substance of those comments is fully incorporated into these comments on the proposed changes to the MMR Rule.]

For too long, however, federal and state policies seeking to reduce GHG emissions have not fully taken into account these scientific findings [See, e.g., Environmental Working Group, Clearcut Disaster: Carbon Loophole Threatens U.S. Forests (June 2010)]. EPA’s proposal is particularly problematic given that subpart D source categories are the exact facilities that are likely to use an increasing amount of biomass in the coming years.

For instance, one report from the Environmental Working Group, which was co-authored by Dr. Mary Booth, has concluded that in the United States, 118 new biomass power plant and co-firing proposals that would use wood as a fuel are currently at various stages of the permitting process. Dr. Booth concluded that reaching a goal of generating 25% of electricity from renewable sources by 2025 “will require the equivalent of cutting between 18 and 30 million acres over the next 15 years” and “[b]y 2030, the equivalent of up to 50 million acres could be clear-cut[.]”. As that report points out, 30 million acres is an area larger than the state of Pennsylvania.

As was detailed in comments by environmental organizations and others on EPA’s Tailoring Rule Call for Information, land clearing and indirect land use changes that could result from irresponsible biomass policies may result in significant GHG emissions. Certain types of biomass feedstocks may not involve significant land clearing (such as certain forestry and timber residues). However, at least for the foreseeable future, the predominant biomass feedstock that

will be used for energy production will likely be whole trees. Therefore, renewable energy and climate change policies that incentivize the use of biomass without an accurate assessment of the GHG emissions associated with specific types of biomass fuels could have unintended consequences that dramatically undermine efforts to combat climate change, and have other detrimental environmental impacts.

For these reasons, EPA should require that all facilities separately report their biogenic CO₂ emissions so that the public may understand how much and by what sectors biomass is being used, whether the amount of biomass used as fuel source is increasing, and – in some cases – the type of biomass being used. There is therefore no scientific or policy-related rationale for this exemption. Moreover, scientific considerations – which must serve as the foundation for any climate change policy to be effective – demonstrate that understanding the emissions associated with biomass fuel is critical.

Finally, the burden required of industry to meet this requirement is small. EPA is exempting only those facilities that are already required to or that already do report their CO₂ emissions under the ARP. Therefore, as compared to other source categories, the relative burden imposed on subpart D source categories by the MMR Rule is minimal – and certainly does not outweigh the public interest in access to this information. Further, EPA in section 98.33(e) provides a methodology whereby facilities monitoring CO₂ using CEMS may calculate in a straightforward manner the amount of their biogenic CO₂ emissions. In addition, we see no reason – and, unsurprisingly EPA fails to provide one – to exempt subpart D source categories from the burden of separately reporting biogenic CO₂ emissions, while imposing this burden on other source categories.

In sum, there is no absolutely no valid justification for EPA’s proposal to exempt subpart D source categories from the requirement that biogenic CO₂ be reported separately. In fact, all considerations of policy and science inevitably lead to the conclusion that to develop effective climate change policies, EPA, the public, and policymakers should be aware of the extent to which – and if possible, the type of – biomass feedstocks that are being used as a fuel source.

We recognize that section 114 of the Clean Air Act provides EPA flexibility in establishing a monitoring and reporting program for GHGs. Nonetheless, EPA’s proposal to exclude only subpart D facilities is not supported by any relevant consideration (and unsurprisingly, EPA fails to provide any justification for the exclusion) and would undermine gaining valuable information regarding, and as such is arbitrary and an abuse of discretion [See *Am. Farm Bureau Federation v. EPA*, 559 F.3d 512, 520-524 (D.C. Cir. 2009)].

Response: EPA does not agree with the comment that EPA would be in violation of the law if it did not require separate reporting of biogenic emissions from Part 75 units; commenters’ arguments to this end are conclusory. For instance, commenters do not explain how cited statutory language regarding coverage of “all sectors of the economy” is dispositive of the type of information that EPA *must* obtain from a source category covered by the rule. Moreover, as EPA recently explained in another GHG reporting rule package, the appropriations language grants EPA much discretion in formulating the reporting rule. 75 FR 39736, 39752 (July 12, 2010). Nonetheless, EPA has decided to require reporting of biogenic CO₂ emissions from Part 75 units starting with the 2011 reporting year.

Please see Section II.C in the preamble to the final rule amendments for additional responses to this comment.

Commenter Name: Stephen E. Woock

Commenter Affiliation: Weyerhaeuser Company

Document Control Number: EPA-HQ-OAR-2008-0508-2375.2

Comment Excerpt Number: 1

Comment: As a first principle, we believe reporting of biogenic CO₂ should be mandatory for all source categories subject to EPA's GHG MRR. It should not be optional, as suggested in the proposed Settlement Agreement with UARG (see details in Attachment A to that proposed settlement agreement). We believe separate reporting of biogenic CO₂ is important because it is consistent with the approach taken in the IPCC and national and regional U.S. GHG inventory frameworks, and it correctly supports the concept that regulating biogenic CO₂ in the U.S. -- whether all or some of the biogenic CO₂ as EPA currently is evaluating [Footnote: See EPA's "Call for information" related to biomass published July 16,2010 (75 FR 41173), as follow-up to the PSD Tailoring rule.] -- in the global warming context is unnecessary. It is unnecessary, as EPA knows, because with respect to CO₂ captured from the atmosphere in the photosynthetic process, the flux of biogenic CO₂ released to the atmosphere during biomass combustion is a net neutral and the CO₂ does not contribute to the overall global GHG inventory. Also, in Weyerhaeuser's view the separate reporting of biogenic CO₂ as supporting information is appropriate for transparency and inventory balancing purposes since biogenic CO₂ is accounted for in the land use portions of the EPA National Inventory.

Not surprisingly, EPA sets out its own reasons for deciding to retain separate reporting of biogenic CO₂ for all facilities in its response to comments on the proposed Mandatory Reporting Rule. Specifically, in response to Weyerhaeuser and others' comments that supported the separate reporting of biogenic CO₂ from other greenhouse gas emissions, EPA says: "...Upon review of the comments, we determined to retain the proposed approach in the final rule. Facilities are not required to count emissions associated with biomass combustion when determining whether they meet or exceed the threshold for reporting, but if the threshold is exceeded they are required to separately report emissions associated with the biomass combustion at the facility. This approach is consistent with IPCC Guidelines for National Greenhouse Gas Inventories, which require the separate reporting of CO₂ emissions from biomass combustion and also the approach taken in the U.S. Inventory of Greenhouse Gas Emissions and Sinks. Separate reporting of emissions from biomass combustion is also consistent with some State and regional GHG programs, such as California's mandatory GHG reporting program, the Western Climate Initiative, and The Climate Registry, all of which require reporting of biogenic emissions from stationary fuel combustion sources. The final rule does not eliminate the requirement to report emissions from the combustion of biomass fuels because they can be used as alternatives to fossil fuels. While this reporting requirement does not imply whether emissions from combustion of biomass will or will not be regulated in the future, the data collected will improve EPA's understanding of the extent of biomass combustion and

the sectors of the economy where biomass fuels are used. It will also allow EPA to improve methods for quantifying emissions through testing of biomass fuels."

We agree with this response-to-comment by EPA, and believed the matter settled. However, the proposed Settlement Agreement re-raises the issue in the context of trying to resolve concerns regarding the substantial and burdensome fossil fuel analyses and additional work beyond what Part 75 already requires. Specifically, the existing requirement to determine and report separately a small fraction of CO₂ that is biogenic in origin amidst the predominant use of fossil fuel at an electric utility plant using CO₂ CEMS and reporting using Part 75 methods appears unreasonable. However, instead of making the separate reporting of biogenic CO₂ more manageable for UARG members, EPA provides a proposed settlement solution --an exemption from reporting biogenic CO₂ and a change in the reporting focus--that we believe is problematic.

The following describes the basis for this comment. The purpose of the Settlement Agreement is, in part, to relieve facilities using Part 75 CO₂ CEMS methods from having to report biogenic CO₂ emissions separate from their fossil fuel emissions. The changes are meant to apply to electric utilities subject to GHG reporting under EPA's GHG Mandatory Reporting Rule at 40 CFR 98 Subpart D (although as discussed later, the proposed rule language appears to exempt any user of Part 75 methods). The specific changes outlined in Attachment A to the Settlement Agreement aim to resolve UARG's challenge to EPA's requirements in Subpart A (General Provisions) at 40 CFR 98.3(c)(4) requiring separate reporting of biogenic CO₂ emissions from all other GHG emissions (whether from fossil fuels or biogenic fuels). Currently, the final regulations issued in 2009 completely separate the reporting of biogenic CO₂ quantities from all other GHG emissions, a practice that is in concert with international and other national and regional protocols and inventories for reporting "Scope I" GHG emissions, as described earlier. Although electric utility combustion units subject to Subpart D are expressly exempted from Subpart C of the MRR (see 40 CFR 98.30(b)(5)), the calculations and other methods for determining what portion of the CEMS total monitored CO₂ emissions that are biogenic CO₂ are provided in Subpart C at 40 CFR 98.33(e)(2). Subpart D units are also referred to Subpart C for methane (CH₄) and nitrous oxide (N₂O) calculations for any fuel used including biomass (see Subpart D 40 CFR 98.43(b), which refers to Subpart C at 40 CFR 98.33(c)). In 98.33(e)(2), reporters actually are instructed first to determine the portion of the total CEMS monitored emissions that are of fossil fuel origin; those fossil fuel CO₂ emissions subsequently are subtracted from the CO₂ CEMS monitor total to obtain and report the separate biogenic CO₂ emissions estimate. This calculation requirement is embodied in equations C-13 and C-14 and the various subparagraphs of 40 CFR 98.33(e)(2). The Settlement's proposed solution would allow Part 75 methods users to report biogenic CO₂ separately on a voluntary basis, and, unlike the current regulation, all reporters would now first report total GHG emissions including biogenic CO₂. Then, only the reporters not using Part 75 methods would still be required to report biogenic CO₂ as a separate line item.

Response: Please see Section II.C in the preamble to the final rule amendments for the response to this comment.

Commenter Name: Kevin P. Bundy

Commenter Affiliation: Center for Biological Diversity
Document Control Number: EPA-HQ-OAR-2008-0508-2385.1
Comment Excerpt Number: 1

Comment: Greenhouse gas emissions from biomass combustion and other “biogenic” sources contribute to global warming and climate change. As set forth in detail in the Center for Biological Diversity’s (Center) recent comments regarding EPA’s Call for Information on treatment of biogenic emissions under the Clean Air Act’s PSD and Title V programs, biomass facilities may have a range of climate footprints depending on fuel sources, combustion methods, and associated land use impacts, but there is no scientific or legal support for treating emissions from these facilities as if they are not “pollutants” or as if they have no effect on the climate. [Footnote: See the comments provided by commenter in DCN: EPA-HQ-OAR-2010-0560-0157 and the associated exhibits in DCN: EPA-HQ-OAR-2010-0560-0158, -0159, -0160, and -0161]

Given the importance of accurately measuring and effectively regulating biogenic greenhouse gas emissions, the Center strongly opposes EPA’s proposal to exempt certain electrical generating units from the requirement to monitor and separately report such emissions. We have reviewed the letter submitted today by Clean Air Task Force and other environmental organizations regarding the Proposed Rule, and we share their concerns. EPA should not exempt sources of biogenic greenhouse gas emissions from monitoring and reporting requirements. It makes no sense even to consider such an exemption while the agency is still working to determine how best to regulate biogenic emissions under the PSD and Title V programs. Rather, EPA should ensure that monitoring and reporting methodologies accurately account for biogenic greenhouse gas emissions, and should use that data to inform policy and regulatory development.

Response: Please see Section II.C in the preamble to the final rule amendments for the response to this comment.

Commenter Name: Stephen E. Woock
Commenter Affiliation: Weyerhaeuser Company
Document Control Number: EPA-HQ-OAR-2008-0508-2375.2
Comment Excerpt Number: 2

Comment: As proponents of acknowledging biogenic CO₂ as a separately inventoried emission in keeping with international and other national protocols and precedent, we prefer to not change the reporting paradigm in the way EPA proposes. EPA’s proposal carries with it, whether intended or not, a distinct policy change implication with respect to separate reporting of biomass emissions under greenhouse gas inventories and climate regulations. It also has the potential to cause a substantial under-representation of biogenic CO₂ emissions in the separate biogenic CO₂ line item while likewise making accurate estimates of the total fossil fuel emissions inventory incalculable. Fossil emissions would be incalculable since the total GHG emissions will contain an unknown quantity of biogenic CO₂ un-reported because of the voluntary nature for some in the separate biogenic CO₂ emissions reporting step.

The following outline some examples of the problems: (1) All electrical generating companies already report individual fuel usages; therefore, calculating and reporting biogenic CO₂ could be very straightforward. All electrical generating companies report fuel usage (by fuel type) to the U.S. Energy Information Administration (EIA). Therefore, calculating the biogenic CO₂ could simply be a matter of using this fuel information and the default biogenic CO₂ emission factors provided in the MRR. (2) Some Part 75 sources will over-report their total GHG emissions. For example, there are many pulp mills, primarily located in the East, that are subject to or use Part 75 methods. These pulp mills typically produce between 70% to 80% of their total energy from biomass fuels (e.g. spent pulping liquor, wood, bark and other wood residuals). Therefore, the total CO₂ (including the biomass CO₂) can be approximately four times larger than the fossil fuel CO₂ emissions alone. As a consequence, if these sources decide not to report biogenic CO₂ separately the total reported GHG emissions would gravely misrepresent the GHG emission impact from these facilities. These facilities would be allowed the option even though they are not classified as electric generating utilities subject to MRR Subpart D because in the proposed Settlement Agreement at two places in Attachment A the modified rule language reads: "Units that use the methodologies in part 75 of this chapter to calculate CO₂ mass emissions are not required to separately report biogenic CO₂ emissions, but may do so as an option." (3) There are electric generating utilities subject to the Acid Rain Program and using a CO₂ CEMS subject to Part 75, thus making them subject to MRR Subpart D, that primarily burn biomass but would have the option to not separately report their biogenic CO₂ emissions. These large biogenic CO₂ emissions would be under-reported on the separate biogenic CO₂ inventory but imply much large total fossil and other GHG emissions in the proposed new primary inventory category that includes biogenic CO₂ emissions. (4) Reporting the biogenic CO₂ with the direct (Scope 1) GHG emissions is in conflict with the WRI GHG Protocol. The Protocol states that "Direct CO₂ emissions from the combustion of biomass shall not be included in Scope I but reported separately". The WRI Protocol is an internationally accepted GHG accounting protocol, used by many organizations, companies and others to consistently account and report GHG emissions. Therefore, combining the biogenic CO₂ with the Scope I GHG emissions is inconsistent with the WRI Protocol, and will cause unnecessary discrepancies between the different GHG reporting programs. (5) The number of affected facilities is much larger than perceived. The perception is the vast majority of sources subject to 40 CFR Part 75 are electrical generating units (EGU). However, as previously mentioned there are many other Part 75 facilities, including pulp mills. Many pulp mills burn coal not only because of its relatively lower cost, but also because of operational necessity. Coal is a source of dry fuel when burning other wetter biomass materials, e.g. wet tree bark (hogged fuel). Therefore, many other Part 75 sources besides EGUs will be affected by this proposed change. (6) Including biogenic CO₂ with the anthropogenic GHG is in conflict with EPA's Green Power Partnership (GPP).

Response: Please see Section II.C in the preamble to the final rule amendments for the response to this comment.

In addition, with respect to the commenter's assertion that EGUs already report individual fuel usage (by fuel type) to the U.S. Energy Information Administration (EIA) we would just point out that EPA contacted EIA in the development of the final rule to see if all biomass combusted is, in fact, reported to EIA under Form EIA-923. We learned that this is not always the case; biomass combusted for test burns, for example, is not necessarily reported to EIA. Nevertheless,

we agree with the commenter's overall argument that there is not a significant burden associated with quantifying this fuel consumption. Today's final rule provides two simplified procedures for quantifying biogenic CO₂ emissions at these part 75 units. Specifically, all facilities, except those combusting MSW and tires, can use the simplified Tier 1 approach, which is based on company records on the quantity of fuel combusted. Further, today's final rule provides an additional method (40 CFR 98.33(e)(6) that allows a reporter to calculate biogenic CO₂ emissions based on the heat input data available in the annual electronic reports submitted under 40 CFR part 75, along with other best available information. For a discussion of the estimated burden associated with today's final rule, please refer to the economics discussion in "Final Part 98 Economics Memo for Revisions Rulemaking" that has been placed in docket EPA-HQ-OAR-2008-0508 for the final rule.

Finally, in developing today's final rule we also reviewed carefully fuel consumption at part 75 units, including the number of units and facilities that would be affected by mandatory reporting of biogenic emissions, and the types and relative amount of biogenic fuel (e.g., whether it is the primary fuel or a secondary fuel) that they are combusting. For this discussion, please refer to the "Background Technical Support Document for the Revisions of Certain Provisions of the Mandatory Reporting of Greenhouse Gases Rule" that has been placed in docket EPA-HQ-OAR-2008-0508 for the final rule

Commenter Name: Lauren E. Freeman

Commenter Affiliation: Utility Air Regulatory Group (UARG)

Document Control Number: EPA-HQ-OAR-2008-0508-2388.1

Comment Excerpt Number: 2

Comment: As promulgated, § 98.36(d) exempts units that report CO₂ mass emissions and/or heat input year-round under Part 75 (including Subpart D units) from the requirement to monitor and report CO₂ by fuel type (including the requirement to monitor and report biogenic CO₂ from combustion of biomass separately from other CO₂ emissions). Although EPA described the rule in its response to comments as providing Subpart D units the choice of monitoring and reporting biogenic CO₂ separately (EPA Response to Public Comments, Volume 16 at 21), that option is not reflected in § 98.36(d) or in § 98.33(e), which sets out the monitoring provisions for calculating biogenic CO₂ from Subpart C units with CEMS but makes no reference to Subpart D units. [Because Subpart C does not apply to electricity generating units that are subject to Subpart D, only those provisions of Subpart C that are specifically referenced in Subpart D apply to Subpart D sources. 40 C.F.R. § 98.30(a)(5).] Section 98.3(c) also includes a requirement (which was not proposed) for facility level reporting of CO₂ emissions from the combustion of biomass fuel, and of CO₂ excluding biogenic CO₂, that inexplicably fails to address how owners and operators of units that are not required to monitor biogenic CO₂ separately can certify their facility level reports. 40 C.F.R. § 98.3(c)(4).

In its Reconsideration Petition, UARG described these inconsistencies and asked EPA to convene a proceeding to solicit comment on these provisions as applied to Subpart D units. UARG noted that units that combust only de minimis amounts of biomass may object to use of the monitoring procedure specified for Subpart C units. UARG's concerns arise in part from the

fact that the Subpart C procedure requires year-round, and otherwise completely unnecessary, sampling and analysis of fossil fuel combusted in order to calculate CO₂ emissions from non-fossil fuel. As a result, sources would be required to conduct fuel sampling and analysis of fossil fuel at units already continuously measuring CO₂ at the stack simply to keep open the option of combusting even a tiny amount of biomass during the year (e.g., perform a test burn).

To address the rule inconsistencies, EPA proposes to revise § 98.33(e) to make clear that Part 75 sources may calculate biogenic emissions separately under Subpart C and to revise § 98.36(d) (and a number of related provisions) to allow (but not require) the reporting of those emissions on a unit-specific basis. Because facilities that do not monitor biogenic CO₂ separately cannot report CO₂ separately, or certify a report as excluding biogenic CO₂ from the reported emission value when those emissions have not been excluded, EPA also proposes to revise § 98.3(c) to require reporting of total CO₂ (i.e., CO₂ including biogenic CO₂) in lieu of reporting CO₂ excluding CO₂. This reporting is consistent with the requirement in Subpart D that units report CO₂ emissions based on their Part 75 reports, which do not distinguish between biogenic and non-biogenic CO₂. [See, e.g., Proposed 40 C.F.R. § 98.33(a)(5)(ii)(D), § 98.36(d)(1)(ii) and (ix), § 98.36(d)(2)(ii)(F) and (I), and § 98.36(d)(2)(iii)(F) and (I). 3 Electricity generating units subject to Part 75 have been reporting total annual CO₂ mass emissions to EPA for more than 10 years, and some for as many as 15 years.] It also is consistent with other existing or proposed provisions that do not require calculation and reporting of CO₂ from biomass combustion. See, e.g., 40 C.F.R. § 98.33(e) (excluding fuels not listed in Table C-1).

Although not required under UARG's settlement agreement, EPA proposes another change relevant to UARG's concerns with the existing rules. Specifically, EPA proposes to remove the existing restriction in § 98.33(e)(1) on use of Tier 1 to calculate and report CO₂ from the combustion of biomass at units that use CEMS to monitor CO₂ (including Part 75 units). EPA correctly determined that there is "no technical basis" for this restriction in the current rules. 75 Fed. Reg. at 48,759. As a result, under EPA's proposal, both Subpart D units and Tier 4 units monitoring CO₂ with CEMS no longer are limited to fuel sampling and analysis of fossil fuel in order to combust biomass. This is a significant improvement in the rules and UARG strongly supports it.

Response: Please see response to comment EPA-HQ-OAR-2008-0508-2375.2, excerpt 2, for the response to this comment.

Commenter Name: David P. Tenny

Commenter Affiliation: National Alliance of Forest Owners (NAFO)

Document Control Number: EPA-HQ-OAR-2008-0508-2373.1

Comment Excerpt Number: 2

Comment: NAFO opposes the proposed rule's change of the existing reporting program to require inclusion of biogenic CO₂ when reporting aggregate annual emissions and to categorically exempt units using the part 75 methodologies from the requirement to separately report biomass emissions. It would be inconsistent with and a reversal of established government precedent and policy for the Reporting Rule to treat biomass emissions identical to other

emissions. As such, it is critical that any amendments preserve the existing Reporting Rule's separate reporting of fossil and biomass combustion. While NAFO supports a regulatory regime that facilitates the use of biomass, the proposed changes to the regulations are far broader than necessary to achieve this goal.

Response: Please see Section II.C in the preamble to the final rule amendments for the response to this comment.

Commenter Name: Lauren E. Freeman

Commenter Affiliation: Utility Air Regulatory Group (UARG)

Document Control Number: EPA-HQ-OAR-2008-0508-2388.1

Comment Excerpt Number: 3

Comment: UARG also requests that the Agency consider allowing Part 75 sources that are applying fuel-specific F-factors to calculate heat input under Part 75 to calculate and report CO₂ from combustion of biomass using the same options provided for calculation and reporting of methane (CH₄) and nitrous oxide (N₂O) in the proposed rule. Although not all biomass fuels are required to be accounted for separately in heat input calculations under Part 75, many units likely are applying a pro-rated F-factor based on an estimated percent of each fuel (biomass and fossil) when combusting fuel mixtures that contain biomass. As a result, a source that has apportioned its Part 75 annual heat input to multiple fuels that include biomass could calculate emissions of CO₂ from biomass combustion (i.e., biogenic CO₂) using the same procedure it uses to calculate emissions of CH₄ and N₂O under proposed § 98.33(c)(4)(ii)(D).

Response: EPA thanks the commenter for the input. Today's final rule provides two simplified procedures for quantifying biogenic CO₂ emissions at these part 75 units. Specifically, all facilities, except those combusting MSW and tires, can use the simplified Tier 1 approach, which is based on company records on the quantity of fuel combusted. Further, today's final rule provides an additional method (40 CFR 98.33(e)(6)) that allows biogenic CO₂ emissions to be calculated based on the heat input data available in the annual electronic reports submitted under 40 CFR part 75, along with other best available information.

Commenter Name: Lauren E. Freeman

Commenter Affiliation: Utility Air Regulatory Group (UARG)

Document Control Number: EPA-HQ-OAR-2008-0508-2388.1

Comment Excerpt Number: 3a

Comment: Although UARG believes EPA's proposed revisions are reasonable and well supported, UARG understand that other industries not involved in the settlement may not support the proposed requirement that all facilities report total CO₂, or agree that all units reporting under Part 75 necessarily should be provided the option of not reporting biogenic CO₂ separately. Specifically, the National Alliance of Forest Owners (NAFO) and the American Forest & Paper Association (AF&PA) articulated concerns in comments on UARG's settlement that the

Agency's revision of the facility level reporting requirement to eliminate the reporting of total non-biogenic CO₂ (i.e., CO₂ excluding biogenic CO₂) for all units was not consistent with other GHG programs, or with those groups' views regarding the distinctly different nature of biogenic and fossil-based CO₂. EPA-HQ-OGC-2010-0575-0009 and 0013. The groups also questioned whether Part 75 units that are combusting primarily biomass ought to be allowed the option of reporting only total CO₂.

UARG shares NAFO's and AF&PA's view regarding the nature of biogenic CO₂, see, e.g., Response of the Utility Air Regulatory Group to the Call for Information on Greenhouse Gas Emissions Associated with Bioenergy and Other Biogenic Sources, EPA-HQ-OAR-2010-0560-0271. UARG also agrees that units combusting significant amounts of biomass are unlikely to opt out of reporting biogenic CO₂, and that preservation of an option for facilities with Subpart D units combusting small amounts of biomass to report total CO₂ from their Part 75 reports does not itself require a change in the reporting requirement for other facilities. In short, while UARG does not believe that EPA's proposal in any way signals a change in the Agency's recognition of the distinction between biogenic and non-biogenic CO₂, or impedes the separate treatment of biogenic CO₂ in future regulatory programs, UARG recognizes that there may be approaches to unit level and facility level reporting of CO₂ other than the current proposal that address its concerns.

For example, EPA could limit the option for reporting total CO₂ to those facilities that are not required to report biogenic CO₂ separately, rather than requiring all sources to report total CO₂. EPA also could establish a de minimis threshold (e.g., five percent of total annual heat input) for the separate reporting of biogenic CO₂ Part 75 sources. UARG looks forward to discussing these alternative approaches with EPA.

Response: Please see Section II.C in the preamble to the final rule amendments for the response to this comment.

Commenter Name: David P. Tenny

Commenter Affiliation: National Alliance of Forest Owners (NAFO)

Document Control Number: EPA-HQ-OAR-2008-0508-2373.1

Comment Excerpt Number: 3

Comment: EPA and other domestic and international organizations historically have recognized and affirmed carbon neutrality in reporting and other contexts. Biomass CO₂ neutrality has been the foundation of American policy. As the EPA has concluded, there is “[s]cientific consensus . . . that the CO₂ emitted from burning biomass will not increase total atmospheric CO₂ if this consumption is done on a sustainable basis.” [Environmental Protection Agency Combined Heat and Power Partnership, Biomass Combined Heat and Power Catalog of Technologies, 96 (Sept. 2007), available at www.epa.gov/chp/documents/biomass_chp_catalog.pdf.]

Consistent with this conclusion, in its most recent GHG inventory, EPA did not include emissions from the combustion of wood biomass in its national emissions totals because it “assumed that the carbon . . . released during the consumption of biomass is recycled as U.S. forests and crops regenerate, causing no net addition of CO₂ to the atmosphere.” [EPA, Inventory

of U.S. Greenhouse Gas Emissions and Sinks: 1990-2008 at 3-10 (April 15, 2010), available at http://www.epa.gov/climatechange/emissions/downloads10/US-GHG-Inventory-2010_Report.pdf.] Similarly, the Department of Energy's (DOE's) Voluntary Reporting of Greenhouse Gases Program, authorized by Section 1605(b) of the Energy Policy Act of 1992, provides for exclusion of combustion of biomass fuels. [See DOE, Technical Guidelines: Voluntary Reporting of Greenhouse Gases (1605(b)) Program (January 2007) at 77 ("Reporters that operate vehicles using pure biofuels within their entity should not add the carbon dioxide emissions from those fuels to their inventory of mobile source emissions because such emissions are considered biogenic and the recycling of the carbon is not credited elsewhere.").]

The international GHG accounting methods developed by the United Nation's Intergovernmental Panel on Climate Change also recognize that biogenic carbon is part of the natural carbon balance and will not add to atmospheric concentrations of carbon dioxide. Similarly, the European Union directive on carbon trading specifies that biomass is considered to be carbon neutral. Therefore, a strong consensus exists that treating combustion of biomass as carbon neutral is scientifically sound. NAFO's recommendations below on the proposed rule are consistent with and supported by this longstanding government policy.

B. The combustion of forest biomass is carbon neutral. The proper EPA policies recognizing carbon neutrality are based on near-universal recognition that greenhouse gases emitted in combustion of fuels derived from biomass should be excluded from greenhouse gas regulations because production and combustion of such fuels does not increase atmospheric carbon dioxide levels. As EPA is aware, growing plants absorb significant amounts of carbon dioxide from the atmosphere. Forests, in particular, sequester massive amounts of carbon dioxide. The process of sequestration and storage is a natural by-product of tree growth. Through the process of photosynthesis, trees take up carbon dioxide from the air and in the presence of light, water, and nutrients, release oxygen and manufacture carbohydrates that are used for metabolism and growth of above and below ground organs. All plant materials are ultimately derived from this carbon dioxide, which is drawn from the atmosphere. When plant biomass materials, such as biofuels made from forest biomass, are burned, the carbon dioxide emitted contains the same carbon that was sequestered by the plant feedstocks. Thus, the combustion of biofuels does not result in net carbon dioxide emissions. All carbon dioxide emitted is a product of carbon dioxide absorbed, making the carbon dioxide released back to the atmosphere a net zero with respect to the natural carbon cycle. In this manner, biofuels from forest biomass are fundamentally different from conventional fuels. Once coal, natural gas, or oil is extracted and combusted, it cannot be replaced. In contrast, the sustainable forest management practiced by the United States forest products industry ensures that there is no temporal imbalance between biogenic CO₂ emissions and CO₂ sequestration and thus no effect on the atmospheric GHG inventory. Indeed, as EPA is aware, carbon stocks in United States forests have been, and continue to, increase. Thus, the forest bioenergy industry is truly carbon dioxide neutral.

Response: Please see Section II.C in the preamble to the final rule amendments for the response to this comment.

Commenter Name: David P. Tenny

Commenter Affiliation: National Alliance of Forest Owners (NAFO)

Document Control Number: EPA-HQ-OAR-2008-0508-2373.1

Comment Excerpt Number: 4

Comment: Under the proposed rule, EPA would amend 40 C.F.R. § 98.3(c)(4)(i)-(iv) to require the applicable source categories to annually report “[a]nnual emissions (including biogenic CO₂) aggregated for all GHG” See 75 Fed. Reg. at 48782. This amendment thus comingles both conventional and biogenic CO₂ emissions and is a direct reversal of the existing regulatory requirement, which requires separate reporting of conventional and biogenic CO₂. Not only would the proposed rule direct entities to include biomass emissions when reporting their aggregate annual emissions, the regulation would state that “[u]nits that use the methodologies in part 75 of this chapter to calculate CO₂ mass emissions are not required to separately report biogenic CO₂ emissions, but may do so as an option.” Id. Other proposed changes—to Sections 98.33(a)(5), 98.33(e), 98.36(d)(1)(ii) and (ix), 98.36(d)(2)(ii), and 98.36(d)(2)(iii)—would similarly adjust the requirements for units using part 75 methodologies so that separately reporting annual CO₂ emissions from the combustion of biomass would be optional. See id. at 48790, 48792, 48797, 48798.

The regulations should not mandate the combined reporting of biogenic and conventional emissions. Such a requirement is flatly inconsistent with established government policies, regulations, and recognition of carbon neutrality of biomass emissions. Specifically, NAFO objects to the proposed rule’s requirement that biogenic CO₂ be included without segregation, as directed by the proposed amendment to 40 C.F.R. § 98.3(c)(4)(i). Doing so would not only be inconsistent with carbon neutrality principles, it would make it impossible for EPA to make accurate estimates of aggregate fossil fuel emissions as the reported annual emissions would include an unknown quantity of biogenic emissions. Moreover, by making it optional for all reporters using part 75 methodologies to separately report biogenic emissions, the proposed rule would likely result in a substantial underreporting of biomass combustion.

EPA should preserve the distinction between conventional and biomass combustion. To the extent situations arise making it difficult for the separate reporting of biomass emissions by some units under existing calculation methodologies, EPA should add flexibility to the calculation process to reduce the reporting burden to manageable levels rather than eliminate all reporting obligations. Exceptions from biomass reporting should only be considered as a last resort, if at all. In the event EPA elects to exempt certain units from the requirement to separately report biomass emissions, it should be set out as an exception to the overall Reporting Rule requirements. In addition, the exception should be drawn narrowly so that it only applies to units that have demonstrated there is a legitimate need. Some of the proposed amendments would affect not only units reporting under subpart D of the Reporting Rules (e.g. electric generating units) but also units in other direct emitter source categories. See e.g. proposed 40 C.F.R. § 98.3(c)(4)(ii) (making separate reporting of biogenic emissions optional for all “[u]nits that use the methodologies in part 75”). As such, EPA’s proposed changes to the Reporting Rule will have ramifications that affect not only electric generating units, but numerous other categories of sources. NAFO believes such a far-reaching rule change is inappropriate as these other source categories have not been a part of the development of the proposed settlement that is the impetus

for the proposed rule changes and certainly have not demonstrated a need to be exempt from the established policy of separately reporting biogenic and fossil fuel emissions.

NAFO thus urges EPA to avoid any exemption from biomass reporting by adjusting the calculation methodologies. However, if EPA rejects this solution, it should narrowly tailor any final rule to address only provisions affecting the specific settling parties, and only to the extent they have demonstrated a legitimate need for special treatment under the Reporting Rule. NAFO also recommends that EPA further clarify that any adjustments to the regulations do not reflect any change in government policy regarding the treatment of biogenic emissions. In other words, NAFO requests that EPA confirm that the proposed rule does not change the well established significant distinctions that repeatedly have been recognized between biogenic and non-biogenic emissions, and that the only reason certain units may be allowed (as a last resort) to include biogenic emissions in their annual reporting of emissions is that they have demonstrated it is necessary to eliminate significant administrative and financial burden. Above all, EPA must ensure that any changes to the Reporting Rule are consistent with the government's longstanding policy that there are significant distinctions between biomass and fossil fuel emissions and that biomass emissions are not counted when estimating CO₂ emissions.

Response: Please see response to comment EPA-HQ-OAR-2008-0508-2375.2, excerpt 2, for the response to this comment.

Commenter Name: David P. Tenny

Commenter Affiliation: National Alliance of Forest Owners (NAFO)

Document Control Number: EPA-HQ-OAR-2008-0508-2373.1

Comment Excerpt Number: 5

Comment: NAFO urges EPA to confirm that the proposed rule would not change, in any way, the fact that the Reporting Rule does not include biogenic CO₂ in its reporting thresholds. Indeed, the proposed changes to the regulations (discussed above) relate only to the Reporting Rule's requirements for annual reports. Biogenic emissions would still not be considered when entities conduct a threshold analysis to determine if the Reporting Rule's requirements are triggered in the first place.

Response: These rule amendments do not change how biogenic CO₂ emissions are considered in a facility's threshold analysis.

Commenter Name: Craig Holt Segall

Commenter Affiliation: Sierra Club Environmental Law Program et. al

Document Control Number: EPA-HQ-OAR-2008-0508-2398.3

Comment Excerpt Number: 6

Commenter Name: Helen D. Silver

Commenter Affiliation: Clean Air Task Force et. al

Document Control Number: EPA-HQ-OAR-2008-0508-2403.2

Comment Excerpt Number: 5

[These two commenters submitted identical comments on this subject.]

Comment: Failure to Require Reporting from Biogenic Fuels. A key component in developing effective climate change policies and regulations is the creation of an accurate, science-based accounting system and inventory of biomass-related emissions that accounts for and enforces the complete spectrum of GHG emissions from biomass. To this end, we strongly oppose the proposed amendments to the GHG Monitoring and Reporting Rule regarding biogenic emissions contained in the proposed settlement between EPA and UARG. First, we explain why the final reporting rule requires biogenic CO₂ emissions to be reported separately, including by source categories covered by subpart D. Second, we explain why, if implemented, EPA's proposed changes could significantly limit the information provided to the public and policy makers about the amount of biogenic CO₂ emissions from these facilities. An accurate, economy-wide inventory of biogenic CO₂ emissions is important because the evidence to date conclusively demonstrates that biomass is not inherently carbon neutral. In fact, recent studies indicate that in some instances replacing fossil fuels with certain types of biomass could result in net increases of GHG emissions. An accurate accounting system and inventory can only be developed based on robust and transparent reporting requirements for biogenic GHG emissions.

The express language of the final reporting rule requires separate reporting of biogenic CO₂ emissions for subpart D and other source categories. The terms in EPA's proposed settlement with UARG would amend the final reporting rule to exempt facilities that report CO₂ emissions pursuant to the requirements of the ARP, see 40 C.F.R. § 75.1 et seq., from separately reporting their biogenic CO₂ emissions. This exemption would apply to certain types of electricity generation units ("EGUs"). See 40 C.F.R. § 98.2(a)(1)(i); see also 40 C.F.R. § 72.6. [Footnote: Certain other facilities that are not required to comply with the ARP but nonetheless do so would also be exempt from separately reporting their biogenic CO₂ emissions. See 75 Fed. Reg. at 48,790 (proposed 40 C.F.R. §98.33(a)(5)(iv)). For the sake of simplicity, throughout these comments these source categories and subpart D source categories are collectively referred to as "subpart D source categories."]

In the Proposed Rulemaking on Amendments, EPA states that "[w]e intended for the reporting of biogenic CO₂ emissions to be optional for units subject to subpart D." 75 Fed. Reg. at 48,751. To that effect, EPA states that subsequent to the issuance of the final reporting rule "EPA . . . has provided guidance that separate reporting of biogenic emissions for units subject to subpart D is optional." *Id.* Again, as an initial matter, the ARP program does not and should not constrain EPA in the GHG context, as that program was not designed to inform climate change policies or to control the emissions of GHGs to combat climate change.

The plain language of the final reporting rule, which clearly requires that subpart D units separately report their biogenic CO₂ emissions, renders EPA's subsequently stated intentions on the subject irrelevant. 40 C.F.R. § 98.3 sets forth the "general monitoring, reporting, and verification requirements" of the rule. See 40 C.F.R. § 98.3 (section title) . That section describes the contents of the annual report to be submitted by reporting facilities. 40 C.F.R. § 98.3(c). For

all facilities required to report direct emissions, with certain exceptions not relevant here, Section 98.3(c) requires that “facilities [] report annual CO₂, CH₄, [and] N₂O . . . as follows”:

(i) Annual emissions (excluding biogenic CO₂) aggregated for all GHG from all applicable source categories in subparts C through JJ of this part and expressed in metric tons of CO₂e calculated using Equation A–1 of this subpart.

(ii) Annual emissions of biogenic CO₂ aggregated for all applicable source categories in subparts C through JJ of this part.

(iii) Annual emissions from each applicable source category in subparts C through JJ of this part, expressed in metric tons of each GHG listed in paragraphs (c)(4)(iii)(A) through (c)(4)(iii)(E) of this section.

(A) Biogenic CO₂.

(B) CO₂ (excluding biogenic CO₂).

(C) CH₄.

(D) N₂O.

40 C.F.R. § 98.3(c)(4)(i)-(iii).

There is no exemption for subpart D source categories that comply with the requirements of the ARP.

As we understand it, EPA’s argument essentially rests on its claim that, because subpart D does not explicitly provide for separate reporting of biogenic CO₂ emissions, such reporting could be read as “optional” under the final rule. See 75 Fed. Reg. at 48,751. This position, however, is further belied by the required contents of the annual report per the provisions of the final reporting rule.

In addition to the above listed requirements in Section 98.3(c), that section also requires that a facility report “[e]missions and other data for individual units, processes, activities, and operations as specified in the ‘Data reporting requirements’ section of each applicable subpart of this part.” 40 C.F.R. § 98.3(c)(4)(iv). The only logical reading of this separate requirement is that compliance with the monitoring and reporting requirements of each specific subpart governing covered facilities is in addition to these general reporting requirements. EPA’s reading therefore would render this separate requirement superfluous. *C.f.* *TRW Inc. v. Andrews*, 534 U.S. 19, 31 (2001) (“It is a cardinal principle of statutory construction that a statute ought, upon the whole, to be so construed that, if it can be prevented, no clause, sentence, or word shall be superfluous, void, or insignificant.”) (citations and internal quotations omitted). Therefore, per the express language of the final rule, it is irrelevant that subpart D does not mandate separate reporting of biogenic CO₂ emissions. EPA in the Proposed Rulemaking on Amendments concedes that the plain language of the finalized reporting rule requires separate reporting of biogenic CO₂ emissions from source categories covered by subpart D:

Section 98.3(c)(4) . . . requires sources to report facility-wide GHG emissions, excluding biogenic CO₂, and to report CO₂ emissions for each for each category excluding [sic] biogenic CO₂ emissions. To meet these reporting requirements, facilities with subpart D and/or other Part 75 Units would have to separately account for the biogenic CO₂ emissions (if any) from those units. 75 Fed. Reg. at 48,751 (emphasis added). Therefore, EPA itself acknowledges that the

provisions of the final rule requiring separate reporting of biogenic CO₂ emissions are “requirements” applicable to source categories covered by subpart D or that otherwise comply with the requirements of the ARP.

Further, it is irrelevant that, since the promulgation of the final reporting rule, EPA has issued Guidance [Footnote: Based on recent communications with EPA, we believe that this guidance refers to a response to a question sent via the “hotline” established for the final reporting rule. We believe that this “hotline” is the “Rule Help Center” webpage at http://www.epa.gov/climatechange/emissions/ghgrule_contactus.htm. It is our understanding that responses to questions sent via this webpage are provided only to the sender of the question and not available for retrieval otherwise. We also note that we were unable to find similar statements by EPA through its electronic “Frequently Asked Questions” system by performing separate searches for the “biogenic,” “biomass,” and “Acid Rain Program.” http://www.epa.gov/climatechange/emissions/ghg_faq.html. Given the difficulty we encountered in identifying and obtaining this guidance and the importance of transparency with respect to the GHG reporting requirements, we urge EPA to make all guidance relating to the final reporting rule readily accessible at <http://www.epa.gov/climatechange/emissions/ghgrulemaking.html>.] indicating that separate reporting of biogenic CO₂ emissions for subpart D source categories is optional. See *id.* The United States Court of Appeals for the D.C. Circuit has made it clear that “[o]nce an agency gives its regulation an interpretation, it can only change that interpretation as it would formally modify the regulation itself: through the process of notice and comment rulemaking.” *Paralyzed Veterans of America v. D.C. Arena L.P.*, 117 F.3d 579, 586 (D.C. Cir. 1997). The guidance exempting subpart D source categories from separately reporting their biogenic CO₂ emissions constitutes a “re-interpretation” of the reporting rule as finalized because, as explained above, it clearly contradicts the express requirements of the final reporting rule. As such, it is not an interpretive rule that “only reminds affected parties of existing duties,” *Assoc. of Am. RR v. Dept. of Transp.*, 198 F.3d 944, 947 (D.C. Cir. 1999) (internal quotations and citations omitted), but rather a substantive rule re-interpreting the final reporting rule to exempt subpart D facilities from the existing requirements of the final reporting rule. See *Paralyzed Veterans of America*, 117 F.3d at 587-88 (stating that a substantive rule is one that has the force and effect of law and that intends to create new rights or duties). Therefore, EPA’s issuance of guidance on this subject is insufficient to modify the requirements of the final reporting rule. See *id.* at 586. [Footnote: Further, it is irrelevant that EPA in its “Response to Comments” stated that subpart D source categories are not required to separately report biogenic CO₂ emissions and that the methodologies in Section 98.33(e) are optional. U.S. EPA, *Mandatory Greenhouse Gas Reporting Rule: EPA’s Response to Public Comments*, Vol. No. 16, Subpart D – Electricity Generation, 21 (Sep. 2009), available at <http://www.epa.gov/climatechange/emissions/responses.html> “Agency interpretations of their own regulations have been afforded deference by federal reviewing courts for a very long time and are sustained unless plainly erroneous or inconsistent with the regulation.” *Paralyzed Veterans of America*, 117 F.3d at 584 (emphasis added, internal quotations and citations omitted). Because the exemption proposed in the guidance directly conflicts with the express requirements of the final reporting rule, it should receive no deference. This is particularly true because, as stated before, EPA concedes that separate reporting of biogenic CO₂ emissions for subpart D source categories is a “requirement” of the final reporting rule. 75 Fed. Reg. at 48,751. Moreover, given that the rule expressly requires that subpart D source categories separately

report biogenic CO₂, it is of little import that section 98.33(e) provides that those source categories “may use” the methodologies to calculate these emissions. 40 C.F.R. § 98.33(e)(2).]

We emphasize that there may be additional arguments that the final reporting rule requires separate reporting of biogenic CO₂ emissions from subpart D and other facilities complying with the requirements of the ARP or that the guidance EPA has issued has no substantive effect, and that these comments are not meant to be exhaustive on these issues.

Response: EPA disagrees with the commenter that the 2009 final rule required separate reporting of biogenic CO₂ emissions for subpart D units, which is why this final rule does not impose that requirement until reporting year 2011. The 2009 final rule clearly stated that if there are any inconsistencies between the general provisions in subpart A and a source category subpart, the source category subpart takes precedence. 40 CFR 98.1(b). Subpart D required reporting of CO₂ reporting “as required under § 75.13... and § 75.64,” and those sections of Part 75 do not require separate reporting of biogenic CO₂ emissions. The only additional requirement under the GHG reporting rule regarding CO₂ emissions from subpart D units was a conversion of short tons to metric tons. Thus, to the extent there are any inconsistencies with the general provisions regarding reporting of biogenic CO₂ emissions and subpart D, subpart D takes precedence. This is consistent with statements in the 2009 proposed rule that “[f]or ARP units, the CO₂ mass emissions data already reported to EPA under part 75 would be used in the annual GHG emissions reports required under this proposed rule.” 75 FR at 16486. Moreover, contemporaneous with the final rule, in response to comments, EPA stated that

It is EPA's intent that Acid Rain Program units will be able to continue to measure and report CO₂ 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 CO₂ emissions; see §98.33(e) of the final rule.

Thus, contrary to commenters’ argument, EPA’s subsequent responses to questions on this topic were not a change in interpretation.

Please see Section II.C of the preamble to the final rule amendments for additional information related to this comment.

As noted by the commenter, we have developed and posted a Frequently Asked Questions database on the website for the Greenhouse Gas Reporting Program. This database can be found at http://www.epa.gov/climatechange/emissions/ghg_faq.html. Given that this is a new Program and EPA is receiving numerous questions, many of which have been submitted by others in the past, we decided to provide an FAQ database to support implementation. The website is clear, however that the searchable FAQ database is intended to provide general and administrative information about 40 CFR Part 98. The database does not provide legal advice, and responses to questions received by EPA do not have legally binding effect or expressly or implicitly create, expand, or limit any legal rights, obligations, responsibilities, expectations, or benefits in regard

to any person. Facility owners or operators and suppliers are responsible for determining how they would be affected by the requirements of 40 CFR Part 98.

Commenter Name: Craig Holt Segall
Commenter Affiliation: Sierra Club Environmental Law Program et. al
Document Control Number: EPA-HQ-OAR-2008-0508-2398.3
Comment Excerpt Number: 7

Commenter Name: Helen D. Silver
Commenter Affiliation: Clean Air Task Force et. al
Document Control Number: EPA-HQ-OAR-2008-0508-2403.2
Comment Excerpt Number: 6

These two commenters submitted identical comments on this subject.

Comment: Separate reporting of biogenic CO₂ emissions is necessary for the establishment of a transparent and complete inventory of economy-wide CO₂ emissions. As explained in comments submitted by these organizations on the proposed mandatory monitoring and reporting rule, EPA's decision to exclude biogenic CO₂ emissions from the determination of whether a facility meets the 25,000 ton CO₂ threshold was erroneous. However, we agree with EPA's determination that once a facility's emissions otherwise meet the reporting threshold, the facility must report its biogenic CO₂ emissions and must report these separately from GHG emissions from the combustion of fossil fuels and other emission sources. See, e.g., 40 C.F.R. §98.2(b)(2).

In the past, EPA has correctly stressed that “[a]ccurate and timely information on GHG emissions is essential for informing many future climate change policy decisions” and that facility specific data is particularly important for understanding factors that influence GHG emissions rates and identifying actions and facilities that could reduce emissions. 74 Fed. Reg. at 56,265. Further, EPA has stated that “[b]esides total facility emissions, it benefits policy makers to understand: (1) The specific source of emissions and the amounts emitted by each unit/process to effectively interpret the data and (2) the effect of different processes, fuels, and feedstocks on emissions.” Id. at 56,277. We agree. The terms of the proposed settlement agreement with UARG, however, run contrary to the principle underlying these statements.

Allowing subpart D source categories to comply with the reporting requirements of the ARP alone could deprive the public of important information on the types of fuels being used and the amount of biogenic CO₂ emissions at these large sources. Pursuant to the finalized mandatory monitoring and reporting rule and EPA's proposed definition of “emission data”, 75 Fed. Reg. 39,094, 39,101 (July 7, 2010), the information currently required to be reported and proposed to be made publicly available would allow the public to easily identify the amount of biogenic CO₂ emissions, 40 C.F.R. § 98.3(a)(4)(ii), and in some cases the amount and fuel type being used, see 40 C.F.R. § 98.33(e)(1) (directing parties that do not use CEMS to monitor CO₂ emissions to calculate biogenic CO₂ emissions based on fuel type and other emissions factors). We are concerned that the proposed amendments, which would not require subpart D source categories to report separately the amount of biogenic CO₂ emissions, could deprive the public of this

valuable information. It is unclear whether this information could be derived from the reporting requirements of the ARP, and even if it could, it is not clear how burdensome such back-calculation would be to the public and policy makers. For instance, facilities reporting under the ARP are required in their quarterly electronic reports to indicate the type(s) of fuel used at each unit, the start and end dates of combustion for each type of fuel, and “whether the fuel is primary, secondary, emergency or start up fuel.” See 40 C.F.R. § 75.53(g)(1)(D); see also 40 C.F.R. § 75.64(a)(2) (requiring electronic, quarterly reporting of certain information in 40 C.F.R. § 75.53). The amount of biogenic CO₂ emissions cannot be calculated by the public and policy makers from that information alone. This is further evidenced by the fact that the quarterly emissions reports under the ARP do not provide information regarding the amount of biogenic CO₂ emissions or the amount of biomass used at a given facility. [Footnote: The quarterly reports are available through EPA’s website, <http://camddataandmaps.epa.gov/gdm/index.cfm>.] It is also unclear to us how regulators themselves would calculate the biogenic CO₂ emissions from these facilities from this and other information required to be reported under the ARP.

Moreover, the burden imposed upon subpart D facilities to calculate these emissions is of little consequence given the importance of this information in developing an accurate GHG emissions inventory to serve as a basis for effective climate change policies. Section 98.33(e) provides a calculation whereby facilities monitoring CO₂ using CEMS may calculate in a straightforward manner the amount of their biogenic CO₂ emissions. 40 C.F.R. § 98.33(e)(2) (74 Fed. Reg. at 56,402). In addition, we see no reason to exempt subpart D source categories from the burden of separately reporting biogenic CO₂ emissions, while imposing this burden on other source categories.

Accurate information regarding the amount of biogenic CO₂ emissions, in particular from the electricity sector, is of the utmost importance in developing effective climate change policies. The scientific evidence to date has dispelled the notion that all biomass is “inherently carbon neutral.” [Footnote: See, e.g., T. Searchinger et al., Fixing a Critical Climate Accounting Error, 326 *SCIENCE* 527 (2009); Manomet Center for Conservation Sciences, Biomass Sustainability and Carbon Policy Study (June 2010) (“Manomet Study”); see also Environmental Working Group, Clearcut Disaster: Carbon Loophole Threatens U.S. Forests (June 2010) (“Clearcut Disaster”), available at <http://www.ewg.org/clearcut-disaster>]. This is particularly a concern when whole trees are used as a fuel source at utility scale electric generation facilities. For instance, the Manomet Study showed that in Massachusetts, replacing coal with biomass derived from whole trees would increase net GHG emissions through 2050 and would achieve only a 19% reduction by 2100. That study also found that, if biomass replaces natural gas at electricity generation units in Massachusetts, there could be more than an 100% increase in GHG emissions through the year 2050.¹⁶ The study also found that by 2100, replacing natural gas with whole trees could cause a net increase of GHG emissions of 63%.

Unfortunately, the scientific evidence dispelling the assumption of inherent carbon neutrality has not been fully taken into account in federal and state policies that seek to reduce GHG emissions from the power and transportation sector. For instance, as explained above, EPA erroneously excluded biogenic emissions in determining whether a facility is required to report its GHG emissions. Until recently, in Massachusetts, woody biomass was considered to be carbon neutral and thus eligible to receive renewable energy credits. In response to mounting

scientific evidence that biomass is not inherently carbon neutral, the Commonwealth suspended the application of renewable energy credits to certain biomass facilities and commissioned the “Manomet Study.” In light of this study’s conclusions, the Commonwealth is in the process of revising its renewable energy policies with respect to biomass-fired facilities.

As the experience in Massachusetts demonstrates, unless and until science-based policies are developed at the state and federal levels that fully account for the GHG emissions associated with biomass combustion, there is a great incentive for utility scale electricity generation facilities and other stationary combustion units to either switch wholesale to biomass combustion or to co-fire biomass and fossil fuels. For instance, one report from the Environmental Working Group, which was co-authored by Dr. Mary Booth, has concluded that in the United States, 118 new biomass power plant and co-firing proposals that would use wood as a fuel are currently at various stages of the permitting process.¹⁸ Dr. Booth concluded that reaching a goal of generating 25% of electricity from renewable sources by 2025 “will require the equivalent of cutting between 18 and 30 million acres over the next 15 years” and “[b]y 2030, the equivalent of up to 50 million acres could be clear-cut[.]” As that report points out, 30 million acres is an area larger than the state of Pennsylvania. [Footnote: Clearcut Disaster: Carbon Loophole Threatens U.S. Forests (June 2010) (“Clearcut Disaster”), available at <http://www.ewg.org/clearcut-disaster>]. Therefore, renewable energy and climate change policies that incentivize the use of biomass without an accurate assessment of the GHG emissions associated with those fuels could have unintended consequences, and have other detrimental environmental impacts.

Some types of highly efficient facilities may result in GHG reductions in the nearer term when using biomass as compared to fossil fuels. For instance, the Manomet Study found that for oil thermal and combined heat and power plants, replacing fossil fuels with whole-tree biomass would result in 25% net reductions of GHG emissions by 2050. By 2100, replacing fossil fuels at these facilities with whole-tree biomass would result in net GHG emissions reductions of 42%. The finding of the Manomet Study that certain forms of biomass-based power generation can provide net GHG reductions within a useful time period as compared to fossil fuels reinforces the point that EPA must require EGUs to report biogenic emissions separately. Without empirical data on the emissions associated with biomass use at EGUs, EPA and other regulators will be hard-pressed to distinguish between biomass-to-power applications that increase net GHG emissions and those that do not.

Given the significant scientific uncertainty about the impacts of shifting electricity generation from fossil fuels to biomass, the incidental burden placed on these facilities to separately report their biogenic CO₂ emissions is of little consequence. We applaud EPA’s commitment to transparency with regard to the GHG emissions inventory and encourage it to publish as much information on its website as it is legally permitted. See 75 Fed. Reg. at 39,099. To that end, EPA should continue to prioritize, in conformity with its Congressional mandate, the development of a comprehensive GHG emissions inventory that covers “all sectors of the economy of the United States.” See Fiscal Year 2008 Consolidated Appropriations Act, Pub. L. No. 110-161, 121 Stat. 1844, 2128 (Dec. 26, 2007). It should also continue to prioritize providing timely and accurate information to both the public and to state and local authorities to aid in the development of GHG emissions reductions strategies. Amending the final reporting

rule to exempt certain facilities from having to separately report their biogenic CO₂ emissions is, however, a step in the wrong direction and could deprive the public and state and local policy makers of important information regarding the use of biomass as a fuel source. To be clear, we are opposed to exempting these facilities from the separate reporting requirements of biogenic CO₂ emissions under the final monitoring and reporting rule. However, should EPA should exempt these facilities, it should do so only upon a showing this information can and will be easily accessible to the public – and policy makers – pursuant to the reporting requirements of the ARP.

Response: Please see Section II.C of the preamble to the final rule amendments for the response to this comment. Please see response to comment EPA-HQ-OAR-2008-0508-2398.1, excerpt 8, for the response to the comment regarding the congressional mandate.

Content of annual report- other amendments

Commenter Name: Joel R. Hall

Commenter Affiliation: Mexichem Fluor Inc.

Document Control Number: EPA-HQ-OAR-2008-0508-2365

Comment Excerpt Number: 2

Comment: Mexichem supports the EPA's proposal to clarify that suppliers of industrial fluorinated GHGs only calculate and report GHG emissions in mtCO₂e for those fluorinated GHGs that are listed in Table A-1 under 40 CFR 98.3(c)(5)(i).

Response: We thank the commenter for the input. We have finalized the proposed requirement to report GHG emissions in mtCO₂e for only those fluorinated GHGs that are listed in Table A-1 under 40 CFR 98.3(c)(5)(i).

Recordkeeping

Commenter Name: Tom Siegrist

Commenter Affiliation: Koch Nitrogen Company LLC (KNC)

Document Control Number: EPA-HQ-OAR-2008-0508-2364.1

Comment Excerpt Number: 1

Comment: EPA's proposal to modify the reporting requirements associated with missing data events will provide EPA with sufficient information to manage the program while simplifying the reporting obligations for reporters. (75 FR 48753) The current language at 40 CFR 98.3(g)(4) requires reporting of the cause of each missing data event, the duration of the event, the corrective actions taken, and the actions taken to minimize occurrence in the future. EPA has concluded that it does not need information regarding the duration of the event or the actions taken to minimize reoccurrence in order to administer the program. KNC agrees that information regarding the event's cause and corrective actions taken should provide EPA with the information needed to evaluate the reliability of the data collection systems in place. Koch

Nitrogen Company, LLC (KNC) supports EPA's proposal to focus its data collection efforts on those two areas.

Response: We thank the commenter for the input. We have finalized the proposed amendments to require only the cause of the missing data event and the corrective actions taken. Please see Section II.E of the preamble for the final rule amendments for the response to this comment.

Commenter Name: Brady W. Wassom

Commenter Affiliation: Environmental Systems Corporation (ESC)

Document Control Number: EPA-HQ-OAR-2008-0508-2367.1

Comment Excerpt Number: 2

Comment: Environmental Systems Corporation (ESC) is also requesting that EPA allow the reporting requirements specified in 40 CFR 75 related to missing data events to satisfy the reporting requirements for missing data events specified in §98.3(c)(8). §98.3(c)(8) requires reporting of each data element for which a missing data procedure was used according to the procedures of an applicable subpart and the total number of hours in the year that a missing data procedure was used for each data element.

In addition, §98.46 requires that the units subject to Subpart D follow the applicable missing data substitution procedures in 40 CFR 75 for CO₂ concentration, stack gas flow rate, fuel flow rate, high heating value, and fuel carbon content. ESC believes that requiring the reporting of missing data events according to the requirements specified in §98.3(c)(8) duplicates the requirements in 40 CFR 75 and will increase the reporting burden for our customers. For example, in the case of CO₂ concentration, units subject to 40 CFR 75 report a method of determination code according to §75.57(e)(1)(viii) for CO₂ concentration which specifies whether the value associated with CO₂ concentration was a valid measurement or substitute value. Through the use of the method of determination codes, the source has already documented the number of missing hours in a reporting period and the methods used for determining each substituted value. Our hope is that EPA recognizes that: (1) facilities subject to the requirements of 40 CFR 75 already report missing data events to the EPA on a more frequent basis (quarterly) than required by 40 CFR 98, (2) such reporting satisfies the intent of the reporting requirements specified in §98.3(c)(8), and (3) EPA will add a clarifying statement to that effect in §98.3(c).

Response: No rule change has been made as a result of this comment. It is true, as noted by the commenter, that some of the same information reported under 40 CFR part 75 is also required to be reported under the requirements of §98.3(c)(8). However, we have concluded that it is important for consistency and comparability across reporting facilities to have information for all missing data events reported under 40 CFR part 98 by all units at all facilities.

We note that facilities reporting under 40 CFR part 98 may include units subject to 40 CFR part 75 as well as other units. Again, for consistency across reporters under 40 CFR part 98 we have determined that it is necessary to have the information reported in one place. For additional information regarding a similar comment to the 2009 final rule, please see response to comment EPA-HQ-OAR-2008-0508-0165, excerpt 6 in Mandatory Greenhouse Gas Reporting Rule: EPA's

Commenter Name: Eldon Lindt

Commenter Affiliation: Xcel Energy Inc.

Document Control Number: EPA-HQ-OAR-2008-0508-2374.1

Comment Excerpt Number: 2

Comment: The final rule requires reporters to document the cause and duration of any missing data event, the action taken to restore the equipment, and the actions taken to minimize future occurrences. Under the proposed revisions, reporters are no longer required to document the actions taken to prevent future reduce missing data occurrences. Xcel Energy supports this change as it is consistent with current Part 75 requirements.

Response: We thank the commenter for the input. We have finalized the recordkeeping requirements for missing data as proposed. Please see Section II.E of the preamble for the final rule amendments for the response to this comment.

Commenter Name: Fiji George

Commenter Affiliation: El Paso Corporation

Document Control Number: EPA-HQ-OAR-2008-0508-2390.1

Comment Excerpt Number: 2

Comment: Reporting requirements related to missing data procedures in §98.3(c)(8): Current language: “Each data element for which a missing data procedure was used according to the procedures of an applicable subpart and the total number of hours in the year that a missing data procedure was used for each data element.” Suggested language with proposed new language in square brackets:

“Each data element for which a missing data procedure was used according to the procedures of an applicable subpart and the total number of hours in the year that a missing data procedure was used for each data element, [for the data elements with hourly collection frequency].”

Incorporation of the requested change will provide clarification for instances where the number of hours related to missing data cannot be easily determined, for example if the data collection frequency is monthly, semiannual, or “twice a year at least four months apart”.

Response: No rule change has been made as a result of this comment. The changes to Part 98 suggested by the commenter are outside the scope of the specific amendments proposed for public comment in the Federal Register notice of August 11, 2010. EPA proposed to amend the recordkeeping requirements for missing data events in 40 CFR 98.3(g)(4) for the reasons described in Section II.E of the proposal preamble. We did not propose to amend the reporting requirements related to missing data events.

Commenter Name: Lauren E. Freeman
Commenter Affiliation: Utility Air Regulatory Group (UARG)
Document Control Number: EPA-HQ-OAR-2008-0508-2388.1
Comment Excerpt Number: 6

Comment: IV. Information to Record for Missing Data Events Section 98.3(g)(4) as promulgated requires, for “each missing data event,” recording of the duration of the event, actions taken to restore malfunctioning monitoring equipment, the cause of the event, and the actions taken to prevent or minimize occurrence in the future. As UARG described in its Reconsideration Petition, the requirement to record the cause of missing data periods and the corrective actions taken can be satisfied for units using CEMS by a simple notation in the maintenance log already required under Part 75, Appendix B, § 1.1.3 (maintenance records). See 40 C.F.R. § 75.57(h). However, there are no requirements in Part 75 to separately record the “duration of the event” or the “actions taken to prevent or minimize occurrence in the future.” Instead, the duration of each missing data event is reflected in the hourly records in the quarterly reports (which are coded to indicate whether the data are from the CEMS or a missing data substitution procedure) and in the percent monitor availability that is calculated and recorded each operating hour. Any actions actually taken to prevent future missing data also would be reflected in the maintenance log as corrective action or maintenance. Requiring sources using CEMS, particularly those already complying with Part 75 recordkeeping, to develop additional records would be overly burdensome and of little usefulness. The majority of missing data periods associated with CEMS are of short duration and are due to routine activities or calibration failures for which there is no clear measure to prevent future occurrence. In response to UARG’s concerns, EPA proposes to revise § 98.3(g)(4) to remove the requirement to record the “duration” of all missing data events and the actions taken “to prevent or minimize occurrence in the future.” 75 Fed. Reg. at 48,753. EPA also proposes to revise § 98.47 to make clear that the records already being retained under § 75.57(h) are sufficient to satisfy this rule. EPA’s proposal is reasonable and necessary, especially with respect to CEMS. Requiring sources to record an action taken to prevent or minimize future occurrence when no such measure is available is not reasonable. Nor does EPA need a rule to require sources to try to prevent missing data. Sources already have adequate incentives to collect data from their monitoring systems, particularly under Part 75 where missing data procedures become increasingly punitive as the length of the missing data event increases and data availability falls.

Response: EPA thanks the commenter for the input. We have finalized the recordkeeping requirements for missing data, as proposed. Please see Section II.E of the preamble for the final rule amendments for the response to this comment.

Commenter Name: Craig Holt Segall
Commenter Affiliation: Sierra Club Environmental Law Program et. al
Document Control Number: EPA-HQ-OAR-2008-0508-2398.1
Comment Excerpt Number: 7

Comment: EPA has offered no compelling justification for waiving some of its 40 C.F.R. § 98.3(g)(3) recordkeeping requirements. EPA proposes to drop recordkeeping requirements for the duration of missing data events and for “corrective actions taken.” 75 Fed. Reg. at 45,752-53. It proposes to do so because the Part 75 Acid Rain Program reporting system does not have this requirement and some reporters have asserted that the continuous emissions monitoring systems (CEMS) used in that program do not offer reporters opportunities to take “clear measures to avoid” missing data events. *Id.* These rationales do not support EPA’s action. Initially, the design of the Acid Rain Program (“ARP”) bears only tangentially on appropriate requirements for the reporting rule, which is far more comprehensive and designed to create a broader range of data. But, even in the context of CEMS used in that program, tracking the duration of outages, and requiring operators to document what action, if any, they intend to take to correct outages, is useful and not burdensome. It creates incentives for accurate reporting, solely at the cost of a few electronic files saved on a reporter’s computer. More importantly, these justifications have no bearing on the far broader class of measurement systems EPA proposes to use in the reporting rule. The vast array of scales, meters, and monitoring systems reporters may use extends far beyond the relatively homogeneous universe of CEMS in the ARP. Even if EPA’s rationales for dropping missing data recordkeeping held true for ARP CEMS, it makes no sense to rely upon that narrow class of instruments to justify waiving these requirements for all other instruments. Indeed, it is precisely this broader class of mechanical systems that is more susceptible to corrective action, as some of its members, such as belt scales, may fail for mechanical reasons that could be corrected with preventative maintenance. EPA has offered no evidence whatsoever that waiving requirements is appropriate for any technology other than CEMS, and so it may not do so. At bottom, by making missing data harder to document, and errors harder to fix, EPA is imperiling the reporting system. It should drop these proposed changes.

Response: We have finalized the recordkeeping requirements for missing data, as proposed. Please see Section II.E of the preamble for the final rule amendments for the response to this comment.

Commenter Name: Lauren E. Freeman

Commenter Affiliation: Utility Air Regulatory Group (UARG)

Document Control Number: EPA-HQ-OAR-2008-0508-2388.1

Comment Excerpt Number: 7

Comment: In its comments on UARG’s settlement, CATF objects to this revision. CATF argues that recording the duration of missing data events is not burdensome because sources already must know the duration in order to calculate missing data substitution procedures. CATF also asserts that, if there is no clear action available to prevent or minimize the occurrence, the requirement is not burdensome because there is not much to record. EPA-HQ-OGC-2010-0575-0014 at 6. CATF misses the point. The mere fact that sources can record the duration of each event separately (and separate from another report, like the Part 75 report) is not a rationale for requiring that it be recorded and CATF provides no independent reason for recording this information. With respect to actions to prevent future missing data, if the rule requires the recording of some action, the fact that there is no action that can be taken does not make the

recording more reasonable, it makes it impossible. Sources should not be required to make up unnecessary tests and actions simply to satisfy a rule. CATF also has offered no evidence that a rule requiring sources to record such actions, where they do exist, would add any incentive to preventing missing data or that sources do not already have adequate incentives to keep their monitoring systems operating. EPA should reject CATF's comments.

Response: We have finalized the recordkeeping requirements for missing data, as proposed. We agree with the commenter that just because source can record the duration of each event separately, does not provide sufficient rationale for requiring that it be recorded. As noted in Section II.E of the preamble for the final rule amendments we have concluded that the information on missing data events reported to EPA under 40 CFR 98.3(c)(8) as well as the recordkeeping requirements provide sufficient information for the GHG Reporting Program. We also agree that commenters have not provided sufficient evidence that providing the additional information on missing data will provide any additional incentive to improve their monitoring practices.

Commenter Name: Helen D. Silver
Commenter Affiliation: Clean Air Task Force et. al
Document Control Number: EPA-HQ-OAR-2008-0508-2403.2
Comment Excerpt Number: 2

Commenter Name: Craig Holt Segall
Commenter Affiliation: Sierra Club Environmental Law Program et. al
Document Control Number: EPA-HQ-OAR-2008-0508-2398.3
Comment Excerpt Number: 3

These two commenters submitted identical comments on this subject.

Comment: Missing Data Provisions Under the proposed UARG settlement, EPA would weaken the rule-wide missing data recordkeeping procedure. See 40 C.F.R. § 98.3(g)(4). UARG would remove recordkeeping requirements for the duration of a missing data event and would also replace records of “the actions taken to prevent or minimize occurrence in the future” with a requirement that companies document “corrective actions taken to restore malfunctioning monitoring equipment.” See 75 Fed. Reg. at 48,752-53. We do not support these changes. EPA justifies these changes because the Part 75 ARP “does not require separate accounting of the duration of [missing data] event[s] or . . . actions taken to minimize occurrence in the future.” 75 Fed. Reg. at 48,753. These justifications are not compelling. Initially, the ARP's requirements do not constrain EPA's obligations in the greenhouse gas context. Because missing data periods allow global warming pollution to go unmeasured, they should be strictly documented and EPA and the public must be able to verify how long they have lasted, and how they will be prevented in the future. As to duration in particular, EPA's concern that this requirement is “overly burdensome” is not compelling. See *id.* Reporters, presumably, would comply with the duration requirement by noting how long a system failed in their general report, or adding a “duration” column to their reporting spreadsheets. This small additional requirement is hardly burdensome. Indeed, to accurately use missing data procedures, reporters must know the duration of missing

data events and so must be collecting this information regardless. EPA should not waive the requirement. The changes to the “minimize occurrence” requirement are even less well-justified. EPA posits that because missing data events “associated with the use of continuous emissions monitors [(‘CEMS’)] are due to routine activities or calibration failures for which there are no clear measures to avoid similar occurrences in the future,” it should eliminate this requirement entirely. 75 Fed. Reg. at 48,753. But most facilities covered by the rule are not using CEMS; indeed, EPA designed the rule in part to avoid requiring CEMS. So, it does not make sense to waive the “minimize occurrence” requirement for this large class of reporters because a subset of facilities do happen to use CEMS. EPA should not be sacrificing incentives to minimize missing data events across the rule because this may be hard to do with some CEMS systems. Indeed, even for CEMS-users, EPA’s justification actually cuts the other way. If, in fact, there are few clear actions available to minimize the failure of these systems in the future, then reporters will not have much to record, and so will not be burdened. On the other hand, such a requirement might help CEMS users discover ways to minimize new system failures – which is also a positive result. The bottom line is that EPA’s concerns are ill-supported. By waiving recordkeeping requirements on the theory that some facilities may not have many records to keep (but, yet, are somehow “burdened”), it weakens requirements for all facilities, including ones whose reporting practices would improve with rigorous recordkeeping requirements. EPA should not make these changes.

Response: We have finalized the recordkeeping requirements for missing data, as proposed. Please see Section II.E of the preamble for the final rule amendments for the response to this comment.

Revisions to the annual GHG report

Commenter Name: Caitlin Post

Commenter Affiliation: Southern Company

Document Control Number: EPA-HQ-OAR-2008-0508-2377.1

Comment Excerpt Number: 2

Comment: EPA is proposing to amend 40 CFR 98.3(h) to clarify what triggers an annual report resubmission and the process for resubmitting the report. Southern Company supports these clarifications. The proposal makes it clear that only a substantive error, which is defined as “an error that impacts the quantity of GHG emissions reported or otherwise prevents the reported data from being validated or verified,” would require a report resubmission. This explanation is necessary because it is impractical to resubmit a report for an error that is unrelated to the reported emissions. The proposal also allows the owner or operator to demonstrate that the report does not include a substantive error or that the identified error is not substantive. Southern Company supports this proposal because there may be instances when something is incorrectly identified as a substantive error.

Response: EPA thanks the commenter for the input. The requirements regarding resubmission of the annual GHG report have been finalized as proposed. Please see Section II.D of the preamble to the final amendments for additional information.

Commenter Name: Rich Raiders

Commenter Affiliation: Arkema Inc.

Document Control Number: EPA-HQ-OAR-2008-0508-2371.1

Comment Excerpt Number: 5

Comment: The § 98.3(h) reporting revision proposal clarifies how EPA and reporters may amend previously submitted GHG reports. However, Arkema requests that EPA clarify the term “substantive error” at proposed 40 CFR 98.3(h). Many errors are possible that would cause a reporter to misstate actual emissions by less than 5%, thus not impacting actual annual GHG emission rates. We request that, in the final preamble, EPA clarify that any error not be considered substantive unless it exceeds 1% to 5% of the total annual CO₂ equivalent (“CO₂e”) emission amount reported by an individual reporting facility. EPA should also modify the “contains one or more substantive errors” language to allow the agency flexibility to investigate potential as well as documented errors. Not all data anomalies detected by EPA staff may be errors. Specifically, reporters under the upcoming Subpart L, Fluorinated Greenhouse Gas Production, will be required to report GHG leak detection and repair (“LDAR”) emissions from manufacturing process equipment. LDAR emission rates of individual constituents in a manufacturing unit vary substantially from year to year. The many GHGs in a Subpart L facility exhibit a wide range of Part 98 Table A-1 global warming potential (“GWP”) values. Slight variations in fugitive leak rates from one section of a reporting facility could cause fugitive GHG emission rates to vary by orders of magnitude from one year to the next. None of this expected process variability constitutes an error, just normal manufacturing activity. As EPA noted at proposed § 98.3(h)(2), some data issues may require nothing more than a clarification statement from a reporter.

Response: No rule change has been made as a result of this comment. Please see Section II.D of the preamble for the final rule amendments for the response to the request to further clarify the definition of “substantive error” and why EPA has determined that it is not appropriate to assign a quantity of emissions (as a percentage of total emissions reported) below which an annual GHG report does not have to be resubmitted. We have also concluded that no rule change is needed to address the commenter’s concern that normal process variability might wrongly be considered a “substantive error”. The final rule contains a provision that, within 45 days, the owner or operator can either resubmit the report correcting any substantive errors or provide information demonstrating that the previously submitted report does not contain the identified substantive error or that the identified error is not a substantive error. Further, this 45 day period may be extended upon request. We have concluded that this additional timing, as well as the ability for the owner or operator to demonstrate that errors are not substantive provides the flexibility requested by the commenter.

Commenter Name: Jamie Mann

Commenter Affiliation: Suncor Energy USA, Inc.

Document Control Number: EPA-HQ-OAR-2008-0508-2389.1

Comment Excerpt Number: 3

Comment: EPA is proposing to amend 40 C.F.R. § 98.3(h) to clarify how a resubmission is triggered and the process for resubmitting annual GHG reports. First, reports would only have to be resubmitted when the owner or operator or the Administrator determines that a substantive error exists. A substantive error would be defined as one that impacts the quantity of GHG emissions reported or otherwise prevents the reported data from being validated or verified. This clarification is important because some errors are not significant (e.g., an error in the zip code) and do not impact emissions. Such "errors" would not obligate the owner or operator to resubmit the annual report. The owner or operator would be required to resubmit the report within 45 days of identifying the substantive error, or the Administrator notifying them of a substantive error, unless the owner or operator provides information demonstrating that the previously submitted report does not contain the identified substantive error or that the identified error is not a substantive error. This proposed change would provide owners or operators the opportunity to demonstrate that what the Administrator has deemed to be substantive errors are not, in fact, substantive errors.

The concept of a "substantive error" was not included in the original August 20, 2009, final GHG MRR rule. This concept appears to be very close to the "material misstatement" concept in the California AB32 Rules, which is defined in the rule as follows [§95102(113)]:

Material misstatement' means one or more inaccuracies identified in the course of verification that result in the total reported emissions, or reported purchases, sales, imports or exports of electricity, being outside the 95 percent accuracy required to receive a positive verification opinion.

This term can be misleading because it is not an indication of the true accuracy of the emission estimate, but is rather an indication of the accuracy of the facility in performing the emissions estimate. In the California Air Resources Board (CARB) document entitled "Mandatory Reporting of Greenhouse Gas Emissions: Instructional Guidance for Operators", CARB clarified the term "material misstatement" is as follows (page 6-2):

To enable a positive verification opinion, a GHG emissions data report must be found by the verification team to be free of material misstatement and to conform to the requirements of the regulation. For an emissions report to be free of material misstatement, the verification team must find that the report contains no errors that could not result in facility-wide CO₂e emissions being less than 95 percent accurate. This means that errors in emissions estimation adding up to 5 percent of the overall facility CO₂e emissions are allowed. For an emissions report to conform to the requirements of the regulation means that regulation standards and methods were observed by the operator in report preparation.

The 5 percent materiality threshold for verification is different than the ± 5 percent accuracy requirement for fuel use measurement required by section 95103(a)(9). Because the verification process allows for the inherent uncertainty associated with allowed instrumentation and emission factors, these additional uncertainties are outside the materiality threshold. The materiality threshold requires that emission factors and calculation methods be applied correctly, to ensure that no significant errors have been

made in the operator's emissions calculation. Errors may be made that result in an overstatement or understatement of emissions, but as long as the absolute errors result in a less than 5 percent error in total facility CO₂e emissions, the emissions data report is deemed acceptable."

EPA has provided very little specific information on how the mandatory GHG inventory data would be used for a cap and trade program. As a result, "substantive error" is used to establish when an emission inventory should be resubmitted to the agency. A "substantive error" can be self determined or identified by the Administrator. Therefore, Suncor Energy U.S.A., Inc. (Suncor) proposes that the changes underlined below be made to the proposed rule definition of "substantive error":

(3) A substantive error is an error that impacts the total quantity of GHG emissions reported for the affected facility or otherwise prevents the reported data from being validated or verified. A substantive error can occur if an emission factor or calculation is not correctly applied. A substantive error is different than an accuracy requirement, such as that for fuel gas metering in this rule.

In addition to the above clarifications, a numerical value such as the five (5) percent of total emissions could be presented to allow a more quantitative measurement of "substantive error." The numerical value may be helpful in allowing the owner or operator to demonstrate if a "substantive error" has occurred.

Response: No rule change has been made as a result of this comment. Please see Section II.D of the preamble for the final rule amendments for why EPA has determined that it is not appropriate to assign a quantity of emissions (as a percentage of total emissions reported) below which an annual GHG report does not have to be resubmitted. We have also not made any changes, as recommended by the commenter, to the definition of substantive error. We do not agree with addition of the suggested sentence that a substantive error can occur if an emission factor or calculation is not correctly applied. While the statement is true, it is not complete, as there are many other causes of substantive errors. For example, a facility might forget to report on a specific unit(s) or they may have used missing data procedures for an underlying parameter, but later realize that reporting could have been completed with actual data and missing data procedures were not necessary. These two events could trigger a resubmission, but would not specifically be related to an emission factor or incorrect application of an equation.

It is clear that the process for resubmission of an annual GHG report, and the identified substantive error that leads to such resubmission, is different than any underlying accuracy requirements in the rule, as the latter refers to the calibration of the specific measurement technologies used to calculate GHG emissions. We have concluded that the suggested change by the commenter is unnecessary.

Finally, the commenter notes that EPA has provided very little specific information on how the mandatory GHG inventory data would be used for a cap and trade program. As noted in the preamble to the 2009 final rule, the data collected under this rule will provide comprehensive and accurate data to inform future climate change policies. Potential future CAA and other climate

policies include a wide range of possibilities. Because EPA does not know at this time the specific policies that may be adopted, the data reported through this rule should be of sufficient quality to support a range of approaches (74 FR 56369).

Commenter Name: Fiji George

Commenter Affiliation: El Paso Corporation

Document Control Number: EPA-HQ-OAR-2008-0508-2390.1

Comment Excerpt Number: 3

Comment: Reporting requirements related to annual GHG report revisions in §98.3(h)(1): Current language, including changes proposed by the EPA: “(1) The owner or operator shall submit a revised annual GHG report within 45 days of discovering that an annual GHG report that the owner or operator previously submitted contains one or more substantive errors. The revised report must correct all substantive errors.” Proposed language with suggested changes in square brackets: “(1) The owner or operator shall submit a revised annual GHG report within 45 days of discovering that an annual GHG report that the owner or operator previously submitted contains one or more substantive errors [that cause a 10%+ change in emissions]. The revised report must correct all substantive errors.”

Response: No rule change has been made as a result of this comment. Please see Section II.D of the preamble for the final rule amendments for why EPA has determined that it is not appropriate to assign a quantity of emissions (as a percentage of total emissions reported) below which an annual GHG report does not have to be resubmitted.

Commenter Name: Lauren E. Freeman

Commenter Affiliation: Utility Air Regulatory Group (UARG)

Document Control Number: EPA-HQ-OAR-2008-0508-2388.1

Comment Excerpt Number: 4

Comment: III. Requirements for Correction and Resubmission of Annual Reports.

As promulgated, § 98.3(h) requires owners or operators to submit a revised report “within 45 days of discovering or being notified by EPA of errors” in an annual GHG report. The revised report must correct “all identified errors.” As described in its Reconsideration Petition, UARG has a number of concerns regarding this rule provision. First, because the annual reports include much more information than calculated GHG emissions data, and must be submitted in the as yet unspecified “format specified by the Administrator,” see, e.g., 40 C.F.R. §§ 98.5 and 98.36, the types of “errors” that could trigger a requirement for resubmission under this rule are almost limitless and go well beyond the errors in “calculation” of data EPA suggested should be corrected under its 2009 proposal. As promulgated, the rule appears to require resubmission for virtually any error identified by the source owner or operator without exception even if discovered years after the original submission was made.

Second, depending upon the mechanism EPA uses to define and identify “errors,” the rule could trigger a requirement for resubmission even when the report is accurate. Because designated representatives (DRs) are required to personally certify all GHG submissions as “true, accurate, and complete,” see § 98.4(e), any rule that would require a DR to submit and certify a revised report based on the Agency’s identification of an error, when the DR continues to believe that the original report is accurate, is not lawful. EPA cannot require DRs to certify what they do not believe.

UARG’s concerns with § 98.3(h) arise as a result of its members’ experience with Acid Rain Program (ARP) reporting under Part 75. In that program, disagreements between EPA and DRs (particularly following a new rule, rule revision, or reporting format change) about the accuracy of reports are not uncommon. Disagreements can arise for many reasons, including as a result of differences in rounding methodologies, differences in rule interpretation, EPA’s use of the reporting “format” to collect information not otherwise required by rule to be submitted, and other errors or programming “bugs” in the electronic data QA checks used by EPA to identify errors. Because EPA has said it intends to use similar electronic QA checks and procedures to identify errors in GHG annual reports, see, e.g., 75 Fed. Reg. at 48,762, 74 Fed. Reg. at 56,278, UARG anticipates that similar issues may arise under the GHG reporting program.

Third, the current requirement to resubmit a report “within 45 days” may not provide sufficient time to determine whether the identified “error” is in fact an error, or to determine the best way to correct an error. Such an inflexible deadline is not appropriate in the context of such an open-ended requirement.

In short, although UARG generally does not object to a requirement to correct and resubmit information an owner or operator believes to be in error, as long as the corrected information is of enough significance to be useful to EPA, UARG does object to any rule that allows EPA to require correction and resubmission where the owner or operator’s DR disagrees with that characterization. EPA proposes to address UARG’s concerns by revising § 98.3(h) to (1) require resubmission only for “substantive errors,” (2) preserve DRs ability to certify reports based on their own factual and legal determinations by allowing them to dispute EPA’s assertion of reporting errors, and (3) allow additional time for resolution of questions regarding identification of errors. 75 Fed. Reg. at 48,752. UARG believes this proposal is not only reasonable, but necessary. If EPA does not revise the requirement to allow DRs to dispute EPA’s error findings, EPA must remove the requirement for DR certification of the GHG reports.

Response: EPA thanks the commenter for the input. The resubmission procedures in §98.3(h) have been finalized, as proposed. Please see Section II.D of the preamble to the final rule amendments for additional information.

Commenter Name: Craig Holt Segall

Commenter Affiliation: Sierra Club Environmental Law Program et. al

Document Control Number: EPA-HQ-OAR-2008-0508-2398.1

Comment Excerpt Number: 5

Comment: We are similarly concerned by EPA’s decision to substantially weaken the rule’s missing data and error correction systems. [See 75 Fed. Reg. at 48,752-53]. For the reasons explained in our settlement comments, we oppose EPA’s proposals to add a complex error correction system, which we believe would substantially increase paperwork and slow error correction, rather than improving information collection systems. We also continue to oppose EPA’s proposal to remove recordkeeping requirements that would otherwise document the duration of missing data episodes and what corrective action reporters need to take to avoid such incidents in the future.

Both of these changes substantially weaken the rule. First, by converting an automatic, and largely ministerial, error correction system into a complex, quasi-adversarial system, EPA swaps quick error correction -- in just 45 days -- for an ongoing debate with operators over whether an error is “substantive,” a question which must be resolved before a correction would be made. See 75 Fed. Reg. at 48,752. The idea, apparently, is to avoid “burdening” reporters with the need to resubmit reports where they have made some relatively minor error. But EPA proposes to use an electronic reporting system, so resubmitting a report should pose no great burden. On the other hand, the system EPA proposes – with reporters and EPA debating whether an error “impacts the quality of GHG emissions reported or otherwise prevents the reported data from being validated or verified,” *id.*, creates a real burden, as reporters will then focus on dueling with EPA, rather than just fixing their mistakes.

Making matters worse, EPA proposes to allow reporters to extend their resubmission deadlines during such debates by at least 30 days, and likely longer (EPA sets no limit on the number or length of these extensions, but should do so). See *id.* The result will be an unwieldy system, with various facilities at different phases in a drawn-out error correction process. This change is a mistake. EPA should stick with its basic, hard deadline of 45 days for resubmission, triggered by any error. As EPA acknowledges, because “it is important to ensure that the most accurate data are available,” a deadline is needed “to ensure EPA receives timely submission of data” and that most reporters simply do not need any extra time. See *id.* If there are odd outlier circumstances where more time is needed, or where resubmission is an insurmountable burden, EPA should deal with these instances by using its enforcement discretion, not by bending its core error correction system out of shape to deal with them. A strong, simple, rule is far preferable here.

Response: Please see Section II.D of the preamble for the final rule amendments for the response to the comment on the resubmission procedures in §98.3(h). We do not agree with the commenter’s views that there is no burden associated with resubmission. While it is true that an electronic reporting format facilitates submission there are inevitably procedures in place at the facility to acquire any necessary additional information and have the report reviewed and approved for submission. Requiring facilities and suppliers to undertake these additional activities, no matter how small, for non-substantive errors, does not provide any additional value to the GHG data collected.

Please see Section II.E of the preamble for the final rule amendments for the response to the comment on missing data procedures.

Commenter Name: Lauren E. Freeman
Commenter Affiliation: Utility Air Regulatory Group (UARG)
Document Control Number: EPA-HQ-OAR-2008-0508-2388.1
Comment Excerpt Number: 5

Comment: In comments on UARG’s settlement, CATF objected to this revision because it does not allow EPA to “trump” an owner or operator’s opinion. CATF also asserts that even nonsubstantive errors should be corrected because resubmitting a report is “just not that burdensome.” EPA-HQ-OGC-2010-0575-0014 at 7-8. As explained above, EPA cannot require a DR to certify the accuracy of a resubmitted report the DR does not believe is accurate. Nor can EPA require sources to submit information that is not required to be reported under the rules, or in a manner that is inconsistent with the rules. EPA cannot both refuse to subject its reporting format and system to rulemaking, and insist that source owners and operators comply with that system without any opportunity to dispute its content or requirements. EPA’s proposed rule represents a reasonable compromise under the circumstances.

CATF also is without any basis to opine on the burdens associated with resubmission. EPA’s reporting format and system are still under development and, unless EPA has shared information with the CATF that it has not shared with the public, CATF has no idea what resubmission will entail. UARG’s experience under the ARP suggests that resubmissions may not be simple. Depending upon how EPA designs the system, resubmission of even one piece of information could require resubmission (and accordingly recertification) of the entire report. If the resubmission takes place after a change in DRs, the new DR also would need to certify the entire report. Resubmission also likely would require the resources of EPA staff to open the receiving system for resubmission and may require replacement of all of the previously submitted information in EPA’s central database. These details will not be known at least until EPA reveals the details of its reporting system later this year, and perhaps not until EPA actually opens its system for submissions. Unless EPA can establish, by subjecting the details of its reporting system, format, and error checking software to rulemaking, that its proposed resubmission requirement will be completely consistent with the rules and easy to implement, EPA must limit its resubmission rule to those elements critical to program implementation, and provide a reasonable process for resolving disputes. EPA should reject CATF’s comments.

Response: EPA thanks the commenter for the input. The resubmission procedures in §98.3(h) have been finalized, as proposed. Please see response to comment EPA-HQ-OAR-2008-0508-2398.1, excerpt 5 for the response to the comment on burden. Please see Section II.D of the preamble to the final rule amendments for additional information.

Commenter Name: Helen D. Silver
Commenter Affiliation: Clean Air Task Force et. al
Document Control Number: EPA-HQ-OAR-2008-0508-2403.2
Comment Excerpt Number: 3

Commenter Name: Craig Holt Segall
Commenter Affiliation: Sierra Club Environmental Law Program et. al

Document Control Number: EPA-HQ-OAR-2008-0508-2398.3

Comment Excerpt Number: 4

These two commenters submitted identical comments on this subject.

Comment: The Error Correction System. Per the UARG settlement, EPA has proposed a byzantine new error correction system. See 75 Fed. Reg. at 48,752. Under the existing rule, operators are required to “submit a revised report within 45 days of discovering or being notified by EPA of errors in an annual GHG report,” correcting all errors. 40 C.F.R. § 98.3(h). This simple requirement ensures that EPA’s database is always up-to-date and relatively error-free. EPA’s new proposal would mire that system in an odd, pseudo-adversarial process, which could take months or longer to correct some, but not all, errors.

As we understand the proposal, the correction system would only be triggered for “substantive errors” – errors which “impact[] the quantity of GHG emissions reported or otherwise prevents the reported data from being validated or verified.” 75 Fed. Reg. at 48,782-83. This term is very much open to debate, as any error will somewhat affect reporting accuracy (even misidentifying the source’s location will make its emissions hard to track, for instance), and EPA invites such disputes. It allows operators, within 45 days of being notified of a substantive error, to show that they did not make such an error, or that the error is not substantive. *Id.* at 48,783.

The proposed rule does not give EPA a clear method to dispute these points with operators, nor provide that EPA’s view trumps the operator’s opinion. Nor does it allow members of the public to argue that an error is, in fact, substantive, and must be corrected. If EPA retains this system, it must correct these flaws to prevent operators from blocking error correction by denying their mistakes are substantive.

That assumes, however, that operators even respond promptly; they may avoid doing so under the proposed rule. There, EPA is allowed to “provide reasonable extensions of the 45-day period for submissions of the revised report” – or “substantive error” claims – and must grant a 30 day extension if an operator requests one “at least two business days” before the period expires. *Id.* The Administrator may then extend the extension still further, by whatever amount “is reasonable.” *Id.*

As a result, operators and EPA may take months, perhaps years, to correct errors, and may still refuse to correct some of them. This is a radical departure from the existing rule, and serves only to hinder what was a straight-forward and effective process.

EPA’s justifications are not compelling. First, as EPA states in the preamble to the proposed rule, “the 45-day time period is a sufficient time period for the vast majority of facilities.” 75 Fed. Reg. at 48,752. In the very rare cases where a facility takes longer, EPA assuredly has enforcement discretion to allow a few delays. It has no warrant to eviscerate the process as a whole because of such possibilities.

Second, there is really no good reason to adopt the “substantive error” dispute process. Resubmitting a report is just not that burdensome – indeed, even without any error correction

system, sources in the ARP have submitted revised data “in less than 45 days after notification or identification of an error.” 75 Fed. Reg. at 48,752. Resubmitting is, certainly, far less burdensome than arguing with EPA about whether an error is “substantive.” In any event, if EPA really is concerned about additional paperwork, it might allow facilities simply to submit error reports, correcting specific data points in their reports, rather than resubmitting all data.

These changes, in sum, cause problems instead of solving them. They imperil data quality, violating EPA’s statutory mandates. EPA should abandon them.

Response: Please see Section II.D of the preamble for the final rule amendments for the response to this comment.

Calibration and accuracy requirements

Commenter Name: Bert Kalisch

Commenter Affiliation: American Public Gas Association (APGA)

Document Control Number: EPA-HQ-OAR-2008-0508-2358.1

Comment Excerpt Number: 1

Comment: In response to comments from APGA and others to EPA on the proposed rule, EPA added a new section 98.3(i)(4) to the final rule intended to exempt fuel billing meters from the annual calibration requirements under the rule. APGA applauds EPA’s decision since few, if any, utilities have the equipment and resources to annually calibrate all their customer meters. Furthermore, as our comments pointed out, utilities have a vested interest in maintaining the accuracy of these meters which are the “cash registers” of the utility business. EPA chose, however, not to exempt fuel billing meters that serve facilities owned by the owner of the utility. The new section reads as follows:

98.3(i)(4) Fuel billing meters are exempted from the calibration requirements of this section, provided that the fuel supplier and any unit combusting the fuel do not have any common owners and are not owned by subsidiaries or affiliates of the same company.

As this provision was not in the proposed rule, APGA did not have the opportunity to provide comments on it during the comment period of the April 10, 2009 notice of proposed rulemaking.

For public gas utilities which are governmental entities owned by the communities they serve, which in turn are owned by the citizens of the communities, e.g. the utility’s customers, this has caused a great deal of confusion. It could be interpreted that public gas utilities must annually calibrate all customer meters, which APGA believe was not EPA’s intent. In addition it appears that the exemption would not apply to fuel billing meters serving government facilities such as city halls, courthouses, schools and other facilities because these facilities are owned by government entities that also own the utility.

APGA urges EPA to delete the phrase “provided that the fuel supplier and any unit combusting the fuel do not have any common owners and are not owned by subsidiaries or affiliates of the same company.”

EPA could also resolve the issue by clarifying that “company” as used in this section, does not include municipal gas distribution systems, public utility districts, county districts, or other public agencies that own and operate natural gas distribution facilities. Public gas utilities are not “companies.”

Response: No rule change has been made as a result of this comment. This comment is out of scope to this rulemaking. The primary purpose of the proposed amendments to 40 CFR 98.3(i)(4) were to include an additional exemption from the calibration requirements of 40 CFR 98.3(i) for flow meters that are used exclusively to measure the flow rates of fuels used for unit startup or ignition. In addition, we also provided clarification that fuel billing meters are not only exempt from the calibration requirements but also the corresponding monitoring plan requirements. EPA did not propose to make any changes to the definition of company in 40 CFR 98.3(i)(4), nor did EPA propose to modify which fuel billing meters are exempted by 40 CFR 98.3(i)(4). However, EPA disagrees with the commenters assertion that Part 98 in any way implies a publicly owned and operated natural gas utility could be required to calibrate all customer meters.

Commenter Name: Michael Hannan

Commenter Affiliation: Williams Olefins LLC

Document Control Number: EPA-HQ-OAR-2008-0508-2357.1

Comment Excerpt Number: 21

Comment: In various parts of the rule EPA uses the terms “consensus-based standards organizations” and “industry consensus standard practice.” However, these are also referred to as “consensus standards organization” and “industry standard practice” in other parts of the rule. The first terms are more descriptive and should be used throughout the rule as follows:

§98.3(i)(1) ***Rather, each of these measurement devices shall be calibrated to meet the accuracy requirement specified for the device in the applicable subpart of this part, or, in the absence of such accuracy requirement, the device must be calibrated to an accuracy within the appropriate error range for the specific measurement technology, based on an applicable operating standard, including but not limited to industry consensus standards and manufacturer’s specifications.***

§98.33(a)(3)(iv) *** You may use a method published by a consensus-based standards organization, if such a method exists, or you may use industry consensus standard practice.*** You may use a density meter calibrated according to the manufacturer’s instructions, a method published by a consensus-based standards organization, or an industry consensus standard practice.***

§98.34(a)(6) *** You may use a method published by a consensus-based standards organization, if such a method exists, or you may use industry consensus standard practice to determine the high heat values.***

§98.34(b)(1)(i)(A) You may use an appropriate flow meter calibration method published by a consensus-based standards organization if such a method exists.***

§98.34(b)(4) *** You may use a method published by a consensus-based standards organization, if such a method exists, or you may use industry consensus standard practice to determine the carbon content and molecular weight (for gaseous fuels) of the fuel.***

Response: EPA agrees with the commenter in part, and has incorporated the recommended change to refer to “consensus-based standards organizations.” We have closely reviewed the suggestion to insert “consensus” after industry to refer to “industry consensus standards.” For some industries, there may be a difference between an “industry consensus standard” and an “industry standard,” the latter of which could be broader and include standards not adopted by consensus-based organizations. When referring to industry standard practices or methods, we wanted to maintain sufficient flexibility to allow appropriate practices or methods to be used, as appropriate, that are commonly used by a particular industry. We determined that not all of these practices and methods would necessarily be adopted by a “consensus” organization and did not want to introduce such a limitation in the final rule.

Commenter Name: Lisa Beal

Commenter Affiliation: Interstate Natural Gas Association of America (INGAA)

Document Control Number: EPA-HQ-OAR-2008-0508-2396.1

Comment Excerpt Number: 3

Comment: The Proposed Rule does not apply consistent nomenclature when referring to methods or procedures, and this could cause confusion. For example, in addition to referencing “consensus methods” or “industry standard practices”, Subparts A and Subpart C also use the following terms: “industry consensus standard method”; “industry consensus standard practice”; “industry consensus standard”; “industry consensus calibration schedule”; and, “industry-accepted or industry consensus standard calibration practice”. The Interstate Natural Gas Association of America (INGAA) understands that rule requirements regarding “methodology” in Subparts A and C generally follow one of three criteria: (1) consensus method (from a standards organization); (2) manufacturer specification; and/or (3) industry standard practice. For clarity, methodologies should be consistently referred to using the same nomenclature and INGAA recommends these three terms.

Response: Please see the response to comment EPA-HQ-OAR-2008-0508-2357.1, excerpt 21, for the response to this comment, particularly with respect to whether the term “consensus” is used after “industry” to refer to “industry consensus standard practices”. In addition, we note that the commenter does not appear to make a distinction between industry “practices” and industry “standards” or “methods.” We recognize that both of these terms are used in the final rule. We concluded that for some industries, a “practice” might not be considered an actual “method.” We did not want to introduce such a limitation in the final rule by switching all uses

of the term “practice” to “method,” nor, conversely did we want to open up all uses of the term “method” to “practice.”

Commenter Name: Lisa Beal

Commenter Affiliation: Interstate Natural Gas Association of America (INGAA)

Document Control Number: EPA-HQ-OAR-2008-0508-2396.1

Comment Excerpt Number: 4

Comment: The Interstate Natural Gas Association of America (INGAA) strongly recommends accepting “industry standard practices” as an option for flow meter calibration in Subpart A and Subpart C, and gas analysis / heating value measurement in Subpart C. Requirements in Subpart A and Subpart C for flow meter calibration (or associated temperature or pressure calibration) include confusing text noted above (e.g., “industry consensus standard practice”). When revising the text, EPA should ensure that “industry standard practices” are retained as an acceptable approach for flow measurement and calibration – including calibration frequency. Similarly, references related to fuel sampling and analysis in Subpart C use inconsistent nomenclature.

When revising for consistent nomenclature, “industry standard practice” should be included as an acceptable approach for natural gas sampling and analysis, including heating value analysis. Company procedures consistent with industry standard practice will be documented in the GHG monitoring plan.

Response: Under the final rule, the General Provisions require that devices be calibrated according to the manufacturer’s recommended procedures, an appropriate industry consensus standard method or a method specified in a relevant subpart of this part (see 40 CFR 98.3(i)). Recalibration must be at the frequency specified in each applicable subpart of this part, or where none is specified, at the frequency recommended by the manufacturer or by an industry standard practice (see 40 CFR 98.3(i)). We agreed with the commenter and removed the term “consensus” after “industry” under subpart C so that flow meters must be calibrated using a method published by a consensus-based standards organization or an industry-accepted practice. Fuel sampling and analysis may be performed using manufacturer’s instructions, methods published by a consensus-based standards organization if such a method exists, or an industry standard practice.

Please see response to comment EPA-HQ-OAR-2008-0508-2357.1, excerpt 21 for the response to the comment about consistent nomenclature. .

Commenter Name: Lorraine Krupa Gershman

Commenter Affiliation: American Chemistry Council

Document Control Number: EPA-HQ-OAR-2008-0508-2368.1

Comment Excerpt Number: 3

Comment: ACC supports EPA’s changes to the MRR language regarding calibration requirements.

Response: EPA thanks the commenter for the input. In general, we have finalized the calibration requirements, as proposed.

Commenter Name: Eldon Lindt

Commenter Affiliation: Xcel Energy Inc.

Document Control Number: EPA-HQ-OAR-2008-0508-2374.1

Comment Excerpt Number: 3

Comment: Under the proposed rule issued August 11, 2010, fuel flow meter calibration requirements do not apply when the use of company records is allowed, or for units calculating CO₂ mass emissions via Part 75. In addition, the proposed rule adds exemptions for fuel billing meters and for fuel flow meters when used exclusively during unit start-up or ignition. Xcel Energy supports these exemptions because it reduces reporting burden, while maintaining the integrity of the emissions report.

Response: EPA thanks the commenter for the input. In general, we have finalized the calibration requirements, as proposed. We would note that we have removed the term ignition from the calibration exemption provision in 98.3(i). Based on comments received, the inclusion of the term ignition had suggested that you need to calculate emissions from all ignition fuels, which is inconsistent with the amendment finalized in 98.30 that reporters don't need to report emissions from pilot lights. If a fuel is used for ignition, but does not meet the requirements necessary to be considered fuel for a pilot light, the ignition fuel may be more generally referred to as a startup fuel and the emissions from consumption of the fuel would still be reported, but the calibration exemption would still apply. Please see Section II.B of the preamble for the final rule amendments for the response to this comment.

Commenter Name: Stephen E. Woock

Commenter Affiliation: Weyerhaeuser Company

Document Control Number: EPA-HQ-OAR-2008-0508-2375.1

Comment Excerpt Number: 5

Comment: §98.3(i)(4): This proposed revision provides an exemption from the calibration requirements for fuel meters exclusively used for startup or ignition purposes. GHG emissions from startup and ignition sources are extremely small compared to the normal operational fuel(s) emissions. This is a reasonable and insightful change that will reduce the unnecessary calibration burden for all sources that employ these devices. Weyerhaeuser supports this revision

Response: EPA thanks the commenter for the input. Please see response to comment EPA-HQ-OAR-2008-0508-2374.1, excerpt 3 and Section II.B of the preamble for the final rule amendments for the response to this comment.

Commenter Name: Karin Ritter
Commenter Affiliation: American Petroleum Institute (API)
Document Control Number: EPA-HQ-OAR-2008-0508-2383.1
Comment Excerpt Number: 20

Comment: API supports the revision of §98.3(i)(4) – Fuel billing meters are exempt from the Monitoring Plan and recordkeeping provisions. Meters used exclusively to measure the flow rates of fuels used for unit startup or ignition are also exempt from the calibration requirements.

Response: EPA thanks the commenter for the input. Please see response to comment EPA-HQ-OAR-2008-0508-2374.1, excerpt 3 and Section II.B of the preamble for the final rule amendments for the response to this comment.

Commenter Name: Stephen E. Woock
Commenter Affiliation: Weyerhaeuser Company
Document Control Number: EPA-HQ-OAR-2008-0508-2375.1
Comment Excerpt Number: 3

Comment: §98.3(i): This proposed revision provides clarification regarding flow meter calibration and the associated accuracy requirements. This revision clarifies that calibration requirements do not apply when company records are used. Weyerhaeuser agrees with this revision because the definition of “company records”, as provided in §98.3(6), does not require any specific calibration methodology or meet any accuracy standard. Therefore, this revision provides the needed consistency with the definition. Weyerhaeuser supports this revision.

Response: EPA thanks the commenter for the input. In general, we have finalized the calibration requirements, as proposed.

Commenter Name: Stephen E. Woock
Commenter Affiliation: Weyerhaeuser Company
Document Control Number: EPA-HQ-OAR-2008-0508-2375.1
Comment Excerpt Number: 4

Comment: §98.3(i)(1): This proposed revision allows the use of applicable operating standards (e.g. industry standards, manufacturer’s specifications, etc.) when calibrating measurement devices. This revision provides greater flexibility for sources to determine the appropriate calibration methodology best suited for their operation. This revision properly addresses the issue of establishing the percent calibration error, rather than specifying a universal value that would apply to all measurement devices. Weyerhaeuser supports this revision

Response: EPA thanks the commenter for the input. The ability to use applicable operating standards has been finalized, as proposed.

Commenter Name: Joel R. Hall

Commenter Affiliation: Mexichem Fluor Inc.

Document Control Number: EPA-HQ-OAR-2008-0508-2365

Comment Excerpt Number: 6

Comment: The calibration requirements of 40 CFR 98.3(i)(2) are not applicable to the manufacturer's recommended procedures for coriolis meters. Mexichem has installed coriolis meters in order to meet certain accuracy requirements of the rule. 40 CFR 98.3(i)(2) requires that the calibration error be calculated at each flow meter measurement point for flow meters other than orifice, nozzle, and venturi meters. Therefore, coriolis meters would be subject to this requirement. Micro Motion's Recommended Calibration Practices for Coriolis meters used to comply with EPA 40 CFR part 98, Green House Gas regulations is to utilize an initial factory calibration in which the % error at each measurement point is calculated and then, for those meters equipped with on-board Meter Verification (MV), to perform the verification once per quarter. If the meter passes the MV, then it is within the manufacturer's specification. The EPA should ensure §98.3(i) contains provisions for coriolis meters and the manufacturer's recommended procedures for calibration. Micro Motion's recommended procedure is located at: http://www.documentation.emersonprocess.com/groups/public_public_mmisami/documents/articles_articlesreprints/mm028843.pdf.

Response: The calibration requirement of 40 CFR 98.3(i)(1) specifies that flow meters must be calibrated according to a manufacturer's recommended procedure, an appropriate industry consensus standard, or the relevant subpart in the rule. As specified in 40 CFR 98.3(i)(5), recalibration must be performed according to the manufacturer's recommended schedule or the appropriate industry consensus calibration schedule. If an individual subpart specifies that meter calibrations must be performed, the procedures of that subpart must be followed. If the manufacturer can provide documentation showing that their calibration schedule will satisfy the calibration accuracy requirements of 40 CFR 98.3(i)(2) for flow meters, then the calibration procedures and schedule specified by the manufacturer will be valid. As such, EPA finds that no further amendments need to be made to accommodate the use of coriolis meters. Regardless of the aforementioned requirements, the monitoring plan requires a description of the procedures and methods that are used for quality assurance, maintenance, and repair of all continuous monitoring systems, flow meters, and other instrumentation used to provide data for the GHGs reported under Part 98. The manufacturer's initial calibration of a coriolis meter must meet the accuracy requirements of §98.3(i)(2). If it does not, a recalibration is required. Once compliance with the accuracy specification has been demonstrated, the manufacturer's recommended recalibration frequency (i.e., recalibrate when the quarterly MV diagnostic test is failed) may be applied. If the commenter elects to use the manufacturer's recommended calibration schedule, the monitoring plan must include a reference to the documentation that establishes how the manufacturer's calibration schedule will continuously meet the applicable calibration accuracy requirements of Part 98.

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2008-0508-2383.1

Comment Excerpt Number: 1

Comment: The Clean Air Task Force, Natural Resources Defense Council, and Sierra Club (collectively, CATF) opposes the Settlement Agreement’s revision to the instrument calibration requirements of 40 C.F.R. §98.3(i) in place of an across-the-board five percent accuracy standard. These revisions are critical, however, because they would specifically tailor calibration requirements to the pertinent equipment and practices in place in the industry, and thus would better accommodate the complexities of the metering and instrumentation systems in a sophisticated refinery or petrochemical manufacturing complex. Contrary to CATF’s assertions, the changes would not undermine the accuracy of the data. Rather, because the revisions would improve the workability of the rule, they are expected to improve the accuracy of the data reported.

Response: EPA thanks the commenter for the input. We have finalized the accuracy requirements, as proposed. Please see Section II.B of the preamble for the final rule amendments for the response to this comment.

Commenter Name: Lauren E. Freeman

Commenter Affiliation: Utility Air Regulatory Group (UARG)

Document Control Number: EPA-HQ-OAR-2008-0508-2388.1

Comment Excerpt Number: 1

Comment: I. Subpart A Calibration Requirements. As promulgated, § 98.3(i) requires (subject to some limited exceptions) that all flow meters and other devices that measure data used to calculate GHG emissions be calibrated prior to April 1, 2010 according to both the procedures specified in paragraph (i) and each relevant subpart of Part 98. In its Reconsideration Petition, UARG objected to the Agency’s failure to reflect in this provision its intent to exclude certain other types of data from the general calibration requirement.

For example, the provision appears to require calibration of fuel flow meters (and other devices) used for “company records” under Tiers 1 and 2, and for “best available information” under various provisions, to meet the same accuracy specification as fuel flow meters required under Tier 3. Requiring calibration of fuel flow meters used to obtain data under provisions that are specifically designed to rely on existing data (rather than require new or revised monitoring) makes no sense. Recognizing this, EPA staff and contractors stated a number of times in training sessions on the final rule that fuel flow meters that are not otherwise required under the rule do not have to meet the calibration requirements of the rule. However, because that intent was not explicitly reflected in § 98.3(i), UARG is concerned that some could argue that the requirement applies despite EPA’s statements. The provisions of § 98.34(g) addressing monitoring plan requirements related to “company records” also could be misinterpreted to suggest that sources must employ new or different procedures to ensure the accuracy of devices used to create those records.

Similarly, § 98.3(i) also includes no exception for sources already complying with the detailed calibration requirements for fuel flow meters under 40 C.F.R. Part 75 (Part 75), Appendix D § 2,

the data from which must be used to report emissions and heat input from electricity generating units under Subpart D. As a result, UARG is concerned that some could argue that sources reporting under Subpart D must comply with the requirements of both rules.

To address these inconsistencies, EPA proposes to revise § 98.3(i) to make clear that the accuracy specifications in that provision do not apply to the use of “company records,” “best available information,” or fuel flow meters or other equipment already meeting the requirements of 40 C.F.R. Part 75, and to remove § 98.34(g). 75 Fed. Reg. at 48,750, 48,792. These revisions are not only reasonable, they are necessary to ensure that that rule is consistent with EPA’s intent not to impose additional monitoring in these cases.

In comments on UARG’s settlement, the Clean Air Task Force, et al. (CATF) objects to EPA’s exclusion of Part 75 sources and “company records” from the calibration requirements in § 98.3(i), arguing that the amendment would destroy the uniform accuracy requirements of the rule. EPA-HQ-OGC-2010-0575-0014. at 3-4. CATF misconstrues the rule. EPA never intended to impose these new accuracy specifications on the types of information addressed in the proposed revision. In the 2009 final rule, EPA determined that the burden associated with certain new monitoring requirements was not justified under some circumstances and adopted a tiered approach to monitoring. With respect to Part 75, EPA determined that the monitoring in Part 75 was more than adequate and therefore required sources already subject to Part 75 to utilize data collected under that rule to report under Part 98 Subpart D. EPA’s proposed revisions to § 98.3(i) to exclude certain types of data simply make this poorly worded provision consistent with EPA’s intent and the rest of the rule. EPA should reject CATF’s comments.

Response: EPA thanks the commenter for the input. We have finalized, as proposed, that the calibration accuracy requirements of 40 CFR 98.3(i) do not apply where company records are used. Please see Section II.B of the preamble for the final rule amendments for the response to this comment.

Commenter Name: Jamie Mann

Commenter Affiliation: Suncor Energy USA, Inc.

Document Control Number: EPA-HQ-OAR-2008-0508-2389.1

Comment Excerpt Number: 2

Comment: EPA has proposed to amend 40 C.F.R. § 98.3(i)(3) to add five conditions (hereafter referred to as Conditions 1 through 5) that must be met in order for a source to use assumed values for temperature and/or total pressure at the flow meter location, based on measurements of these parameters at a remote location (or locations). Conditions 1 through 5 are stated as follows:

(1) The owner or operator would have to demonstrate that the remote readings, when corrected, are truly representative of the actual temperature and/or total pressure at the flow meter location, under all expected ambient conditions. Pressure and temperature surveys could be performed to determine the difference between the readings obtained with the remote transmitters and the actual conditions at the flow meter location.

(2) All temperature and/or total pressure measurements in the demonstration must be made with calibrated gauges, sensors, transmitters, or other appropriate measurement devices.

(3) The methods used for the demonstration, along with the data from the demonstration, supporting engineering calculations (if any), and the mathematical relationship(s) between the remote readings and the actual flow meter conditions derived from the demonstration data would have to be documented in the monitoring plan for the unit and maintained in a format suitable for auditing and inspection.

(4) The temperature and/or total pressure at the flow meter must be calculated on a daily basis from the remotely measured values, and the measured flow rates must then be corrected to standard conditions.

(5) The mathematical correlation(s) between the remote readings and actual flow meter conditions must be checked at least once a year, and any necessary adjustments must be made to the correlation(s) going forward.

Suncor Energy U.S.A., Inc. (Suncor) proposes that EPA delete the language "under all expected ambient conditions" and replace that language with "under standard conditions" in the Condition 1 requirement "to demonstrate that the remote readings are truly representative of the actual temperature and/or total pressure at the flow meter location under all expected ambient conditions." The variability of temperature and pressure throughout a refinery fuel gas system is dependent upon several factors, not limited to only ambient conditions, but also to the presence of steam tracing, piping insulation, etc. Such a change in language is consistent with the requirement in Condition 4 that "the temperature and/or total pressure at the flow meter must be calculated on a daily basis from the remotely measured values, and the measured flow rates must be corrected to standard conditions. Without the requested change, an owner/operator could not satisfy Condition 1, notwithstanding that it satisfies Condition 4.

Additionally, Suncor proposes that EPA clarify Condition 4 for the requirement that "the temperature and/or total pressure at the flow meter must be calculated on a daily basis from the remotely measured values, and the measured flow rates must then be corrected to standard conditions." Due to the dynamic nature of a refinery fuel gas system and the proposed conditions, it appears that the proposed rule requires the development of a dynamic model to provide daily correction factors at all expected ambient conditions which would require temperature and pressure data that is currently not collected. In order to collect data needed to develop the correlations, Suncor would need to install temperature and pressure measuring devices throughout the facility or commission an extensive survey of the fuel gas system. The first option invalidates the need to use remote temperature and pressure data and the purpose of the proposed rule change. The second option requires an extensive and costly survey of the fuel gas system as well as annual verification of the survey. Suncor believes that the cost to install temperature and pressure monitoring devices at all fuel flow meters was not considered in the cost analysis for the rule as originally proposed or for the proposed changes. Suncor also believes that the burden imposed by these conditions (i.e., the ability to compensate for all ambient conditions on a daily basis through the use of detailed pressure and temperature surveys) is not

adequately reflected in the cost analysis for this proposed rulemaking despite the fact that it will require both significant initial and ongoing expenditures. Therefore, Suncor proposes that EPA allow owner/ operators the ability to calculate the temperature and/or total pressure at the flow meter using remote pressure and temperature data under standard conditions.

Response: No rule change has been made as a result of this comment. The change recommended by the commenter to replace the words “under all expected ambient conditions” with “under standard conditions” is not appropriate because the goal of using remote temperature and pressure readings is to determine viable correlations between those readings and the actual conditions at the meter, over the range of ambient conditions typically encountered at the facility, and not just under standard conditions. The temperature correlation, in particular, can be affected by the outside air temperature. Although there may be other factors, as described by the commenter, that affect these correlations, we believe that data obtained through temperature and pressure (T and P) surveys, if documented as described above, can provide sufficiently reliable estimates of the temperature and pressure at the meter.

The commenter also expresses concern about the cost associated with this approach, believing it would require an extensive survey of their fuel gas system and development of a "dynamic model" to provide daily correction factors. However, reporters are not required to conduct the remote surveys or to develop the correlations for temperature and pressure at the meter location. Use of remote transmitters is simply an option that is intended to reduce burden. It is also consistent with recommendations made by industry. Industry representatives have indicated that conditions at a flow meter can, in many cases, be reliably and accurately predicted from temperature and pressure readings made at locations remote from the flow meter. They have further suggested that temperature and pressure surveys can be performed to demonstrate this, and that "active compensation", which is the periodic, automated feed of the remote T and P measurements into the metering calculation system algorithms, is feasible (see Background Technical Support Document for Revisions of the Mandatory Reporting of Greenhouse Gases Rule in Docket HQ-OAR-2008-0508). Therefore, we have concluded that we should retain these optional procedures and finalize them, as proposed. If the commenter elects not to implement these procedures, then for each orifice, nozzle or venturi flow meter that is used to provide data for the GHG emissions calculations, if temperature and/or pressure transmitters are lacking, the necessary transmitter(s) must be installed and calibrated, in accordance with § 98.3(i)(3)(i).

Commenter Name: Sean M. O'Keefe

Commenter Affiliation: Alexander & Baldwin, Inc.

Document Control Number: EPA-HQ-OAR-2008-0508-2380.1

Comment Excerpt Number: 2

Comment: EPA has also proposed to add clarifying language in section 98.3(i) (4) stating that flow meters used exclusively to measure flow rates of fuels "used for unit startup or ignition" are exempted from calibration requirements. EPA correctly notes in the preamble (page 48751) that "the amount of fuel used for ignition and startup generally provides a very small percentage of

the annual heat input (less than 1 percent in most cases)", making rigorous calibration of meters used exclusively for startup and ignition fuels unnecessary.

Response: EPA thanks the commenter for the input. Please see response to comment EPA-HQ-OAR-2008-0508-2374.1, excerpt 3 and Section II.B of the preamble for the final rule amendments for the response to this comment.

Commenter Name: Craig Holt Segall

Commenter Affiliation: Sierra Club Environmental Law Program et. al

Document Control Number: EPA-HQ-OAR-2008-0508-2398.1

Comment Excerpt Number: 1, 2, 3, 4

Comment: We are particularly concerned by EPA's proposal to remove the rule-wide accuracy standard presently codified at 40 C.F.R. § 98.3(i). See 75 Fed. Reg. at 48,750-51. At present, that requirement requires that all "measurement devices . . . be calibrated to an accuracy of 5 percent." 40 C.F.R. § 98.3(i)(1). This sort of rule-wide accuracy requirement is necessary to provide cross-comparable and accurate data, as even small calibration errors can rapidly propagate through reporting data, producing major errors. For this reason, peer systems, including the European Union's emissions reporting, requires regular "uncertainty assessments" and specifies accuracy requirements, including, for instance, a "maximum uncertainty" of just 1.5% for large combustion sources. [See 2007/589/EC Commission Decision of 18 July 2007 establishing guidelines for the monitoring and reporting of greenhouse gas emissions, Annex II at § 2.1.1.1, available at <http://eurlex.europa.eu/LexUriServ/LexUriServ.do?uri=CELEX:32007D0589:EN:NOT>, and attached as Ex 3]. It is therefore extremely troubling to see EPA abandon this requirement, and we discussed it at length in our comments on the settlements.

EPA proposes to specify that the 5% accuracy requirement will apply only to flow meters, and only where a particular sectoral reporting regulation (e.g., for oil and gas systems, or stationary combustion sources), so specifies. See 75 Fed. Reg. at 48,750. This decision is unacceptable. Initially, EPA itself acknowledges that it has "many years of experience with fuel flow meter calibration" and "is confident" that a 5% accuracy threshold is "both reasonable and achievable for such meters." *Id.* It is therefore arbitrary and capricious, in light of EPA's reporting mandate, to waive this requirement for any flow meters. All such meters should be required to meet these minimum accuracy requirements, with no exceptions.

EPA has proposed essentially to waive accuracy requirements altogether for all other measurement devices. In the existing rule, EPA applies the 5% requirement to "all measurement devices," 40 C.F.R. § 98.3(i)(1) (emphasis added), including "belt scales" and other such mechanisms. *Id.* But now EPA specifies that "weighing devices" will escape this requirement and instead have to meet either accuracy requirements in a given subpart (where they exist), or nebulous "appropriate, technology-based error-limits, such as an industry consensus standards or manufacturer's accuracy specifications."

Although EPA states that these “consensus standards” will be documented in the monitoring plan for a given facility, the result will be a nation-wide patchwork of varying calibration requirements and a concomitant patchwork of data accuracy, rendering emissions comparisons and policy development very difficult. EPA has left itself without a clear process or standard for disapproving a given calibration approach, and these approaches are likely to vary widely. Nor will they necessarily meet the practical data quality requirements of the rule, as a given “industry consensus” may well have developed before the rule existed, be influenced by other factors not relevant to EPA’s mandates, or low-ball possible accuracy efforts to save some expenses. The public, too, may be unable to access some calibration “standards” if industry attempts to claim them as confidential, or relies upon expensive private protocols.

The upshot is that EPA’s proposal trades a simple, rule-wide accuracy requirement for a confusing, facility-by-facility approach that will make data more opaque, less reliable, and less useful. EPA offers no rational, record-supported reason for this switch. See *Motor Vehicle Mfrs. Ass’n of U.S., Inc. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 44 (1983) (“[T]he arbitrary and capricious test applie[s] to rescissions of prior agency regulations.”). Indeed, we can find no evidence in the record that EPA has even considered how its proposals would affect the rule’s data quality, quantified any increase or decrease in uncertainty caused by its proposals, identified which “industry consensus” or other standards might be used, and in which industries, with what sort of accuracy and precision, or whether those standards would be public. Nor has the agency considered whether the resulting data from EPA’s proposals could reliably be used to develop policy, inform the public, and support any ultimate emissions reduction policy, including a carbon market, pricing system, or regulatory control technology approach. Instead, EPA appears simply to have ceded the floor to industry pressure. See *id.* at 46 (agency rescission is invalid where agency “apparently gave no consideration whatsoever” to important issues). We expect any final rule to abandon this flawed approach.

There is one bright spot. We are pleased to see that EPA plans to specify that data following a “failed flow meter calibration” would be treated as invalid from the “hour of the failed calibration and continuing until a successful calibration is completed.” 75 Fed. Reg. at 48,750. It is entirely appropriate to invalidate such faulty data. EPA should apply this approach more broadly to any failed calibration, and, further, should make clear that failing to successfully and quickly calibrate measurement instruments violates the rule, opening facilities to enforcement action.

Response: Please see Section II.B of the preamble for the final rule amendments for the response to this comment.

Commenter Name: Helen D. Silver

Commenter Affiliation: Clean Air Task Force et. al

Document Control Number: EPA-HQ-OAR-2008-0508-2403.2

Comment Excerpt Number: 1

Commenter Name: Craig Holt Segall

Commenter Affiliation: Sierra Club Environmental Law Program et. al

Document Control Number: EPA-HQ-OAR-2008-0508-2398.3

Comment Excerpt Number: 2

These two commenters submitted identical comments on this subject.

Comment: Calibration and Accuracy Requirements.

To fulfill its purpose, the reporting rule must produce accurate data that can be readily compared across sources and industry categories. Data will not be cross-comparable – or accurate – if different reporters use materially different calibration methods, or calibrate to different levels of accuracy. Put differently, 1 ton of carbon dioxide, reported with a possibility of 5% error, is quite different than 1 ton of carbon dioxide reported with 10% error. We were therefore very pleased to see EPA include a general calibration accuracy requirement of 5 percent in the final rule, see 40 C.F.R. § 98.3(i)(1), as well as detailed, specific calibration and measurement protocols, see 40 C.F.R. § 98.34, and are very disturbed that EPA has proposed to remove these requirements.

EPA's proposed settlements with the Utility Air Resources Group ("UARG") and the American Petroleum Institute ("API") would delete portions of the general calibration requirement along with industry-specific measurement protocols. In its proposed rulemaking, EPA responds to a "great deal of concern in the regulated community," and proposes to limit the general accuracy requirement solely to flowmeters in narrowly-defined contexts. See 75 Fed. Reg. at 48,569-51. These decisions are serious errors, and conflict with EPA's mandate to build a comprehensive greenhouse gas reporting system. [Footnote: We note, however, that some of the flowmeter-specific calibration requirements that EPA proposes are helpful, such as requiring detailed correlation analyses for data gathered from remote locations. See 75 Fed. Reg. at 48,570-71.]

The core problem is that uniform calibration requirements are needed to assure that data is accurate, and uniformly so across reporting categories. Without uniform requirements, it will be difficult for EPA, the public, or regulators and participants in any carbon control program, to assure that emissions reductions are consistent and verifiable. The reporting rule already suffers somewhat from this problem because it allows many sources to use emissions estimation approaches which are generally less accurate than direct emissions measurement. The proposed settlements exacerbate this flaw by waiving the Section 98.3(i) calibration requirement for many sources – including sources in the Acid Rain Program ("ARP"), those using company records to report, those without flowmeters, and, startlingly, for any source, even one with a flowmeter, if its industry-specific subpart does not "specif[y]" such requirements. See 75 Fed. Reg. at 48,782-85.

All other measurement devices are to be calibrated to accuracy requirements in industry-specific subparts of the rule – where such requirements exist – or "to an accuracy within the appropriate error range for the specific measurement technology, based on an applicable operating standard, including but not limited to industry standards and manufacturer's specifications." 75 Fed. Reg. at 48,783. This change, demanded by API, does serious damage. It will leave EPA and the public in the dark, even if EPA requires such methods to be "documented in the written Monitoring Plan," *id.*, because the change has no real substance. It is not at all clear what an "appropriate" error range is, nor which standards a reporter will deem "applicable." Worse, these standards

include, but are “not limited” to industry standards and manufacturer’s specifications, meaning reporters could presumably come up with their own “standards.”

The upshot is that, by radically limiting the calibration requirements, in response both to the proposed settlements and to general political pressure, EPA is risking the integrity of the reporting rule. This risk is made even more acute by the agency’s simultaneous proposal to delete specific monitoring and quality control protocols from the rule.

These changes mean that not only would calibration be subject to vague industry standards, but underlying measurements would be as well. Under the UARG settlement, for instance, EPA would strike a list of approved high heat value measurement methods from 40 C.F.R § 98.34(a)(6); the API settlement would make similar changes to 40 C.F.R. §§ 98.244 & 98.254. Rather than using specific measurement methods, reporters would have the option of using “methods published by a consensus standards organization if such a method exists” or an undefined “industry consensus standard practice.” See, e.g., 75 Fed. Reg. at 48,795.

EPA does not explain how it will determine whether an “industry consensus” in fact exists, what it will do when different reporters identify different “industry consensus” practices, how it will enforce this nebulous standard, or how it will verify emissions data reported with such a wide range of methods. It will also make it difficult for the public to correctly interpret monitoring data, even though a monitoring plan should define the methods used, because methods will vary from source to source – and some operators may improperly try to claim some subset of their methods are confidential business information. At a minimum, then, EPA should define the term and set out hard rules for determining whether a consensus exists and whether it has been appropriately followed.

But even if EPA began to specify what this new standard means, the rule’s accuracy will still suffer. Industry consensus methods may well produce variably accurate results, leading to growing uncertainty within the data. Because EPA has also largely jettisoned rule-wide accuracy requirements, there is nothing to constrain “industry standard” practices from producing large uncertainties. Industry may agree that it can only measure a given variable to 30% error, based on standard practice, for example. Without calibration requirements, under the proposed settlement EPA will apparently have to settle for this inaccurate data.

The upshot is that, by proposing to remove both industry-specific measurement requirements and rule-wide accuracy measures, EPA risks losing control of the rule’s data quality. It should change course.

The most sensible way to do so is to retain and strengthen the existing rule’s requirements. That is the course we recommend. Alternately, if EPA can substantiate that it needs to set a lower calibration requirement (7.5% or 10%, say) for some devices on technical impossibility grounds, it might do so, without departing from the general principle of rule-wide accuracy requirements. If EPA takes any other course, which we strongly oppose, we request that it at least (1) carefully define “industry consensus” methods and address the verification and enforcement issues we have identified and (2) conduct a thorough uncertainty analysis of its proposal, documenting the

degree of additional uncertainty, including in terms of tons of emissions potentially missed, that its proposals will create.

We understand EPA's concern, expressed at a meeting with the agency, that specifying particular measurement protocols makes it harder to track improving practices, as a rulemaking is required to alter the mandated protocols. If EPA, motivated by this reasoning, wishes to provide for more methodological flexibility, it should do so only if it sharply constrains the uncertainty that flexibility produces. EPA should do so by maintaining and strengthening the uniform calibration requirements. That way, even if individual reporters have some flexibility, they will have to demonstrate that their methods comply with general data quality standards.

Such requirements can be successfully implemented. The European Union's emissions reporting system, for instance, generally allows for methodological flexibility, but constrains all emitters by uncertainty tiers, requiring, for instance, that large general combustion sources report data "within a maximum uncertainty of $\pm 1.5\%$." [Footnote: see 2007/589/EC Commission Decision of 18 July 2007 establishing guidelines for the monitoring and reporting of greenhouse gas emissions, Annex II at § 2.1.1.1, available at <http://eurlex.europa.eu/LexUriServ/LexUriServ.do?uri=CELEX:32007D0589:EN:NOT> .] Reporters, in turn, must conduct careful "uncertainty assessment[s]" where they are not following approved methods, "which shall provide written proof of the uncertainty level associated with the determination of activity data for each source stream in order to demonstrate compliance with the uncertainty thresholds." [Footnote: See Commission Decision § 7] EPA could take a similar course.

In sum, accuracy requirements are at the core of a sound reporting system. The rule as promulgated sensibly imposes both rule-wide requirements and industry-specific methodologies. By abandoning both of these principles, EPA undermines the rule.

Response: EPA disagrees that the removal of the rule-wide 5% calibration accuracy requirements and the removal of specific test methods and standards in favor of the use of methods more broadly adopted by consensus-based standards organizations will detrimentally affect data quality in the GHG Reporting Program. Please see Section II.B of the preamble for the final rule amendments for the response to this comment regarding the removal of the 5% calibration accuracy requirements. We would also point the commenter to the Background Technical Support Document for the Revisions proposed rule (EPA-HQ-OAR-2008-0508) which illustrated that application of technology specific accuracy requirements will, in many cases, lead to a higher standard than the 5% requirement.

With respect to the removal of specific test methods in favor of the use of manufacturers' specifications or industry consensus standards, we would note that we have not removed all test methods. Rather, the decision was made on a subpart-specific basis. Please see section II.G of the preamble for our response to this comment. The commenters are also concerned that EPA does not explain how it will determine whether an "industry consensus" in fact exists, what it will do when different reporters identify different "industry consensus" practices, how it will enforce this standard, or how it will verify emissions data reported using different methods. We would note that the rule does, in fact, point to examples of specific consensus-based standards organizations (e.g., ASTM, ASME, AGA, API, etc.) that would be appropriate for meeting the

requirements of a consensus-based standards organization. We would expect that different reporters in the same industry might use test methods from different organizations and disagree with the commenter that this variation should be a concern. The use of different methods by reporters in the same industry would have been allowed under the 2009 final rule as well, as these different test methods were incorporated by reference in the 2009 final rule. Rather than being a concern, one benefit of opening up specific sections of the rule to the use of industry consensus standards is the ability of reporters to use the same general methods (e.g., ASTM, ASME, AGA, API, etc) but using *more updated, improved versions* of those methods. We also disagree that this change will have an impact on the verification process, as EPA will still be able to do the same type of verification regardless of the proposed revisions.

Finally, the commenters are concerned that more uniform requirements are needed to assure EPA, the public and regulators of the quality of the data for achieving compliance with an emissions reduction program. Our decision to remove the use of specific test methods for some subparts or to remove the blanket accuracy requirement across the rule should not be seen as a signal of how any potential future emission reduction program might be structured. This is a reporting program, not a reductions program. The decisions made now reflect our determination of what is most appropriate for a GHG reporting program and like other key elements of the program (e.g., the use of calculation or direct measurement approaches), would be re-assessed if such reporting is part of any potential future emissions reduction program. See generally, Vol. 9 Response to Comments, Legal Issues on the 2009 final MRR, pp. 14-15 (“EPA is well aware that it may become appropriate to revise this rule in the future to reflect subsequent activities or requirements.”).

Commenter Name: Michael Hannan

Commenter Affiliation: Williams Olefins LLC

Document Control Number: EPA-HQ-OAR-2008-0508-2357.1

Comment Excerpt Number: 20

Comment: Revise §98.3(i)(1) to include product flow meters.

§98.3(i)(1) Except as provided in paragraphs (i)(4) through (i)(6) of this section, flow meters that measure liquid and gaseous fuel feed rates, process stream flow rates, or feedstock or product flow rates and provide data for the GHG emissions calibrations, shall be calibrated prior to April 1, 2010 using the procedures specified in this paragraph (i) when such calibration is specified in a relevant subpart of this part.***

Response: No rule change was made as a result of this comment. The commenter did not provide sufficient rationale as to why these “product” flow meters should specifically be referenced in §98.3(i). We would note that excluding specific references to these product flow meters from §98.3 (i) does not exempt product flow meters from calibration and accuracy requirements, rather it means only that reporters must follow applicable operating standards for calibration of these devices. The rule only specifically refers to calibration accuracy requirements of product flow meters in one place, §98.244(b)(2). §98.244(b)(2) does refer back to §98.3(i), and as such, the accuracy specifications in §98.3(i)(2) and (i)(3) would apply.

Commenter Name: Michael Hannan
Commenter Affiliation: Williams Olefins LLC
Document Control Number: EPA-HQ-OAR-2008-0508-2357.1
Comment Excerpt Number: 45

Comment: Revise §98.3(i)(4), the fuel billing meter QA/QC exemption, to include feedstock and product custody transfer meters. The exemption for fuel billing meters recognizes that meters used for financial transactions are likely to be very well maintained and operated; therefore, the exemption should be extended to include feedstock and product custody transfer meters, which generate data for financial transactions (i.e., billing). If this suggestion is accepted, then a provision analogous to the Tier 3 QA/QC exemption at §98.34(b)(1)(iii) should be placed in §98.244(b) as shown below. Regardless of whether or not this comment is accepted, the citation for the recordkeeping exemptions should be revised to include paragraph (g)(6).

§98.3(i)(4) Fuel billing meters and feedstock and product custody transfer meters are exempted from the calibration requirements of paragraphs (g)(5)(i)(C), (g)(6) and (g)(7) of this section; provided that the feedstock or fuel supplier, or product purchaser, and any unit utilizing the feedstock, combusting the fuel, or supplying the product do not have any common owners and are not owned by subsidiaries or affiliates of the same company.***

§98.244(b) *** Feedstock and product custody transfer meters are exempted from the initial and ongoing calibration requirements of this paragraph and from the Monitoring Plan and recordkeeping requirements of §98.3(g)(5)(i)(C), (g)(6) and (g)(7), provided that the feedstock supplier or product purchaser and the unit utilizing the feedstock or supplying the product do not have any common owners and are not owned by subsidiaries or affiliates of the same company.

Response: EPA agrees with the commenter that the exemption in §98.3(i)(4) should include paragraph (g)(6), and we have amended the rule to include this reference. The other suggested changes to §98.3(i)(4) and 98.244(b) have not been included in the final amendments because we have concerns that custody transfer meters for feedstock and products may not represent the actual amount of material used in or produced by a process. For example, a portion of the material that is used as a feedstock for a petrochemical process may be used in other processes, as fuel, or lost through equipment leaks. If this occurs, then the flow measured by the custody transfer meter would overstate the amount of material actually fed to the petrochemical process. Similarly, product flow measured by custody transfer meters, particularly if located at customer's facilities, may understate the amount of product actually produced. Furthermore, if a given product is purchased by multiple customers, then each customer would have to have a custody transfer meter. Summing the results from each of these custody transfer meters would result in greater uncertainty in the total flow relative to using the results from one flow meter.

Measurement device installation

Commenter Name: Anonymous

Commenter Affiliation: None

Document Control Number: EPA-HQ-OAR-2008-0508-2353

Comment Excerpt Number: 2

Comment: My only concern with this proposed rule is the way in which you will evaluate the petitions made by facilities that claim that they are unable to follow the scheduled shut-down of facilities because they are in need of more time to update and make changes to their facilities. This information is found in Subpart A under general provisions of best available monitoring methods.

Response: Please see Section II.A of the preamble to the final rule amendments, where specific criteria for approval of the extension requests are described

Commenter Name: Peter Zalzal

Commenter Affiliation: Environmental Defense Fund (EDF)

Document Control Number: EPA-HQ-OAR-2008-0508-2370.1

Comment Excerpt Number: 1

Comment: Environmental Defense Fund (EDF) supports the Agency's efforts to develop a robust greenhouse gas reporting rule covering "all sectors of the economy," consistent with legislative mandate. We share EPA's concern that the final Mandatory Reporting Rule provides accurate, timely, facility-specific data, equipping policymakers and the public alike with the information necessary to respond to the challenges and opportunities associated with climate change. In light of these goals, we respectfully offer the below comments, which specifically address the Agency's proposal to extend the use of best available monitoring methods ("BAMM") for certain facilities until December 31, 2015.

EPA is proposing to establish a new petition process, allowing for facilities reporting under subpart P (hydrogen production), subpart X (petrochemicals production), and subpart Y (petroleum refineries) to use BAMM past the current December 31, 2010 deadline. 75 Fed. Reg. at 48748. EPA's proposal allows these facilities to petition for extended use of BAMM if "compliance with a specific provision in the regulation required measurement device installation, and installing the device(s) would necessitate an unscheduled process equipment or unit shutdown or could only be installed through a hot tap." Id. If an affected facility does not have such a shutdown scheduled prior to the December 31, 2010 deadline for full compliance, the facility can petition for an extension, allowing it to use BAMM until December 31, 2013. Id. EPA has additionally proposed to allow facilities taking advantage of this initial BAMM extension request to file an additional, subsequent request, potentially extending the facility's use of BAMM until December 31, 2015. Id. EPA's proposal, then, opens the door for affected facilities to request the use of BAMM for five years beyond the Agency's original deadline.

Consistent data are an inextricable piece of any high-quality greenhouse gas emissions inventory, as they allow comparisons among similarly situated facilities. EPA has recognized the critical importance of consistent data collection in its Mandatory Reporting Rule, noting “[t]he goal of this rule is to collect accurate and consistent data of sufficient quality to inform future CAA policy and regulatory decisions.” 74 Fed. Reg. 56260, 56279 (Oct. 30, 2009). Facilities calculating emissions using BMM, however, undermine the consistency of the dataset. The best available monitoring methods facilities can use to determine important measurement values include:

- (1) Monitoring methods currently used by the facility that do not meet the specifications of a relevant subpart;
- (2) Supplier data;
- (3) Engineering calculations; and
- (4) Other company data.

74 Fed. Reg. at 56274. In its final MRR, EPA determined that this sacrifice of accuracy and consistency was necessary to give facilities an additional year, at most, to come into full compliance with the Rule’s requirements. Here, EPA’s proposal to prolong full compliance with the MRR’s requirements for an additional five years is simply too long, especially given the significant greenhouse gas emissions attributable to these facilities. [Note: According to EPA’s MRR, hydrogen production accounts for 15 million metric tons of CO₂ equivalent (“mmtCO₂e”), petrochemical production accounts for 54.4 mmtCO₂e, and petroleum refineries account for 204.7 mmtCO₂e. 74 Fed. Reg. at 56363. EPA estimates that these facilities account for roughly 6 percent of economy-wide emissions. *Id.*]

Given the critical nature of this data, we strongly encourage EPA not to extend the use of BMM any longer than its initial re-proposed deadline of December 31, 2013. Moreover, with respect to the Agency’s decision to allow an extension until December 31, 2013, we respectfully ask that the EPA provide a more thorough analysis of challenges associated with timely installation of the required measurement devices, set forth manifest decision criteria for allowing any extensions, and establish procedures for applying these decision criteria to the particular facts of any BMM request. EPA does not quantify or evaluate the key factors that inform its decision to extend BMM past the current December 31, 2010 deadline. And the Agency does not provide for the critical fact-based determinations on the administrative record that will provide the basis for the Agency’s judgment. This analysis is the hallmark of reasoned decision-making. Conversely, the failure to provide clear decision-making criteria and to provide for fact-based findings in specific instances would be quintessentially arbitrary and capricious given the Agency’s previously-stated expectation “that the vast majority of facilities will begin complying with the full monitoring requirements of the rule no later than April 1, 2010, and will not require or be granted an extension.” 74 Fed. Reg. at 56275.

Response: Please see Section II.A of the preamble for the final rule amendments for a general response to this comment. In addition, we would note that the overall quantity of emissions that could be reported using best available monitoring methods for the limited extension of time is not as large as suggested by the commenter. Not all greenhouse gases emitted by facilities using the BMM extension would be calculated and reported using a best available monitoring

methodology, rather only those specific pieces of equipment at the facility where it is satisfactorily demonstrated that the required monitoring equipment cannot be installed absent a shutdown of the unit or a hot tap.

The commenter also appears concerned that best available monitoring methods may include supplier data, engineering calculations, or other company data. In general this is true. However we would also point out that unlike the 2010 BMM process, as part of the approval of the extension request for BMM, EPA will also approve the method proposed to calculate GHG emissions in the interim. Therefore, there will be a clear record of an approved approach that facilities must follow in calculating GHG emissions.

The commenter also requests that EPA set forth criteria for allowing any extensions and establish procedures for applying these decision criteria to the particular facts of any BMM request. As proposed, the final rule requires the owner or operator to demonstrate to the Administrator's satisfaction that it is not reasonably feasible to install the measurement device without a process equipment or unit shutdown, or through a hot tap, and that the proposed method for estimating GHG emissions during the time before which the measurement device will be installed is appropriate. To do this, the extension request must contain very specific information, including, identification of the specific measurement device (and location) for which the request is being made, the specific rule requirements requiring the measurement device, reasons why the needed equipment could not be installed before April 1, 2010, or by the expiration date for the use of best available monitoring methods under §98.3(d), documentation showing that it is not practicable to isolate the process equipment or unit and install the measurement device without a full shutdown or a hot tap and that there was no opportunity during 2010 to install the device, and a description of the proposed best available monitoring method for estimating GHG emissions during the time prior to installation of the meter. These are very clear criteria against which each individual application for BMM will be evaluated. Because each specific application request will be unique, EPA cannot further delineate key factors that would inform its review of any given request at this time.

Finally, we disagree with the commenters' suggestion that EPA should approve BMM for no later than December 31, 2013. For reasons provided in section II.A of the preamble for the final rule amendments we have determined that having a two-phase approach, with the first phase ending in 2013 and the second phase no later than 2015, is appropriate and provides a clear and documented approach that ensures that EPA is still receiving data of a known and appropriate quality without unnecessarily forcing shutdowns for these facilities.

Commenter Name: Lorraine Krupa Gershman

Commenter Affiliation: American Chemistry Council

Document Control Number: EPA-HQ-OAR-2008-0508-2368.1

Comment Excerpt Number: 2

Comment: ACC supports EPA's proposal to establish a new petition process in 40 CFR 98.3(j) that would allow for the use of BMM past December 31, 2010 for owners and operators

required to report under subparts P (Hydrogen Production), X (Petrochemicals Production), and Y (Petroleum Refineries). We agree with EPA's rationale that a number of these facilities may not have a process or unit shutdown scheduled for several years, and that requiring the installation of a measuring device may result in an unplanned shutdown. ACC strongly recommends, however, that the BMM extension should extend to any and all facilities subject to any subpart in the MRR that would have to undertake an unplanned shutdown to accommodate the installation of a required measurement device.

Response: No rule change has been made as a result of this comment. Please see Section II.A of the preamble for the final rule amendments for the response to this comment.

Commenter Name: Robert Rouse

Commenter Affiliation: The Dow Chemical Company

Document Control Number: EPA-HQ-OAR-2008-0508-2366.1

Comment Excerpt Number: 1

Comment: The Proposed Language in 98.3(j) should be modified to allow all source categories to seek an extension for the use of best monitoring methods, and EPA should not require sampling and analysis of a stream that is dangerous to monitor due to the presence of toxic chemicals.

The proposed changes to the rules include the addition of 98.3(j) that allows facilities with source categories under subpart P, subpart X, and subpart Y to receive an extension of best monitoring methods beyond December 31, 2010. Dow clearly understands the need for such a provision and supports this proposed addition. However, Dow believes this extension should apply to all source categories in need of such relief should they need to execute a process shutdown to install the necessary measurement devices. There is no logical reason for making this extension available to only some of the source categories when all facilities would have the same constraints and burdens regarding the installation of measurement devices.

Dow has two boilers at one of its facilities that require the use of Tier 3 calculation methods. One of the fuel streams for these units is an off-gas process stream that provides greater than 10% of the annual heat input and contains significant quantities of hydrogen cyanide. This stream is unsafe for routine sampling required by the Tier 3 calculation methods. Contract laboratories contacted also expressed concern with analyzing these samples for safety reasons. A letter was sent to EPA on January 22, 2010 inquiring the best mechanism to address situations such as this, where a fuel stream is unsafe to sample. We were instructed to submit a request for an extension under the rules, and that EPA would further consider this situation. Dow requested and received an extension, but no additional guidance has been provided. Dow has since initiated a project to install the necessary equipment to allow the use of the Tier 4 calculation methodologies. The estimated cost for this project is \$300,000. This is a fairly significant cost that is only needed to determine the emissions of 25% of the fuel use in the equipment. These boilers receive fuel streams from and provide steam to several manufacturing plants at the facility. Current logistics make it problematic to shutdown the equipment needed to install this equipment prior to the end of 2010.

Presently, EPA does not have any provision in the GHG reporting rule for fuel gas streams that are dangerous to sample due to the presence of toxic chemicals. EPA should allow use of company records or process knowledge to estimate fuel use and calculate GHG emissions rather than forcing these sources to sample these toxic streams, or install, operate and maintain CEMS under the Tier 4 method. Alternatively EPA could allow the use of the "fuel gas" factors that are proposed for additions to Table C-1. This would eliminate the need for personnel to handle these toxic chemicals, or in the above case, the need to install, operate and maintain CEMS under the Tier 4 method.

EPA should make provisions for fuel streams containing toxic chemicals and modify the proposed 98.3(j) to include all source categories covered by the rule.

Response: No rule change has been made as a result of this comment. Please see Section II.A of the preamble for the final rule amendments for the response to this comment.

Commenter Name: Jamie Mann

Commenter Affiliation: Suncor Energy USA, Inc.

Document Control Number: EPA-HQ-OAR-2008-0508-2389.1

Comment Excerpt Number: 1

Comment: EPA has proposed that a new petition process be established under 40 C.F.R. § 98.3(j) that would allow use of BMM past December 31, 2010 for owners and operators required to report under subpart P (Hydrogen Production), subpart X (Petrochemicals Production), or subpart Y (Petroleum Refineries). Specifically, EPA is proposing to amend 40 C.F.R § 98.3(i)(6) to account for units and processes that operate continuously with infrequent outages and that cannot meet the flow meter calibration deadline without disrupting normal process operation. A petition for the use of BMM beyond December 31, 2010 would require measurement device installation, and installing the device(s) would necessitate an unscheduled process equipment or unit shutdown or could only be installed through a hot tap.

EPA has specifically requested comment on this conclusion and whether there are other facilities beyond those specified in subparts P, X, and Y that would require a shutdown, or a hot tap, in order to install the required measurement devices.

Suncor Energy U.S.A., Inc. (Suncor) was granted approval by EPA of an extension request to use BMM for temperature and pressure-compensated gas flows through December 31, 2010. In order to develop temperature and pressure-compensated gas flows, Suncor has elected to install a multi-variable monitor capable of measuring flow, temperature, and total pressure. Suncor's compliance strategy was premised on the rejection by EPA of the portion of Suncor's extension request that requested an extension until the next scheduled process unit turnarounds at Suncor's Commerce City Refinery. Based on the changes to the GHG Mandatory Reporting Rule proposed by EPA, Suncor would have the flexibility originally requested in Suncor's BMM extension request, and may therefore elect to implement a different and preferred compliance strategy. Additionally, because the proposed changes have not been finalized, the installation by

Suncor of the multi-variable monitor under the current BMM extension request may not meet the data collection requirements of the final rule. Accordingly, Suncor believes EPA should extend existing BMM extension requests for temperature and pressure-compensated gas flows through December 31, 2011, so that sources such as Suncor may avoid having to install a monitor that may not comply with the final rule, resulting in additional, unnecessary economic burdens of having to install one or more subsequent flow meter(s).

Furthermore, Suncor requests that EPA clarify that a petition for the use of BMM beyond December 31, 2010, would be permitted for emission sources regulated under subpart C (General Stationary Fuel Combustion Sources) at Petroleum Refineries. Specifically, the installation of flow meters and transmitters in order to meet the Subpart C Tier 3 requirements for combustion of refinery fuel gas would require a shutdown or hot tap of a refinery fuel gas system for many refineries. Numerous heaters, boilers, and other combustion units at refineries will require the use of BMM beyond December 31, 2010, with respect to units that have not been shutdown since the original rule proposal and are not scheduled to be shutdown until after December 31, 2010. Suncor believes that EPA's intention was to include Stationary Combustion Sources subject to Subpart C at Petroleum Refineries subject to Subpart Y as sources that are able to make the petition for an extended BMM period and believes this should be explicitly stated in the final rule.

Response: It is not necessary for EPA to extend all existing BMM requests through December 31, 2011. Subpart P, X, and/or Y owners or operators that currently have approval to use BMM, may request an extension under the final rule amendments, if installation of the measurement devices would require a process unit shutdown or hot tap. Owners or operators requesting to use BMM beyond 2010 are required to electronically notify EPA by January 1, 2011 that they intend to apply for BMM for installation of measurement devices and certify that such installation will require a hot tap or unscheduled shutdown. They have until February 15, 2011, to submit the full extension request for BMM. Owners or operators that notify EPA of their plan to apply for BMM by January 1, 2011 and subsequently submit a full extension request by February 15, 2011, can automatically use BMM consistent with their request through June 30, 2011. The post 2010 BMM extension requests described in §98.3(j) are for facilities subject to P, X and/or Y and may cover units that are subject to any subpart of the rule, including subpart C units.

Regarding the temperature and pressure transmitters specifically, EPA did not propose to change the 2009 final rule requirements for pressure and temperature transmitters. Rather, we proposed an additional option to allow facilities to use remote temperature and/or pressure transmitters to determine conditions at the meters. Because we did not propose to change the requirements in the 2009 final rule there is no basis for facilities requiring additional time to install measurement devices consistent with those same requirements. Therefore, no rule change has been made as a result of this comment.

Commenter Name: Helen D. Silver

Commenter Affiliation: Clean Air Task Force et. al

Document Control Number: EPA-HQ-OAR-2008-0508-2403.2

Comment Excerpt Number: 8

Commenter Name: Craig Holt Segall

Commenter Affiliation: Sierra Club Environmental Law Program et. al

Document Control Number: EPA-HQ-OAR-2008-0508-2398.3

Comment Excerpt Number: 1

These two commenters submitted identical comments on this subject.

Comment: The current rules require installation of meters and other measurement devices by April 1, 2010, with extensions available through December 31, 2010. 40 C.F.R. 98.3(d)(1) and (2). As noted by EPA, “it is important to establish a date by which all equipment must be installed and operating in order to ensure that consistent data are collected by all reporters.” 75 Fed. Reg. at 48748; see also 74 Fed. Reg. at 56274 (final reporting rule). We are in full agreement with EPA that timely installation of measurement equipment is a critical component of the reporting rule for ensuring accuracy and consistency. For these reasons, we oppose EPA’s proposal, based upon the API settlement, to provide additional extensions of up to 5 years beyond its original extension deadline for hydrogen and petrochemical production facilities, as well as petroleum refineries.

We are cognizant of the complex nature of these facilities and the various schedules for taking equipment out of service. However, we also believe that the need to install measurement equipment for reporting rule purposes should be a significant consideration in planning scheduled shutdowns. The current rule provides an incentive for subpart P, X and Y facilities to prioritize scheduled shutdown of units requiring measurement equipment. In contrast, EPA’s new proposal would potentially let these sources off the hook for many years down the road. EPA should consider at most a single tier extension program ending in December 2013.

In addition, the rule should make use of unplanned outages as opportunities to install the required equipment sooner rather than later. Many facilities will experience unplanned unit shutdowns before their schedule outages. EPA should require facilities to prepare device installation plans and acquire devices as soon as possible, such that devices can be installed during unplanned shutdowns where feasible.

Furthermore, the deadlines for requesting the second tier extension come too late in the game and appear to create significant gaps in the program’s coverage. Currently, a source must request permission to use best available monitoring methods (“BAMM”) beyond March 31, 2010 by filing a request for extension with EPA several months in advance. 40 C.F.R. § 98.3(d)(2) (request for extension submitted no later than 30 days after effective date of the GHG reporting rule) and 74 Fed. Reg. 56,260 (GHG reporting rule effective date of December 29, 2009). By requiring the extension request to be submitted prior to the deadline for ending BAMM, the rule aims at ensuring that sources at all times are authorized to use BAMM, i.e., are not unjustifiably avoiding installation of measurement equipment.

The same is not true for the proposed second extension period for hydrogen and petrochemical facilities and refineries. The proposal similarly requires a source to submit an initial notification of the intent to submit an extension request for use of BMM beyond December 31, 2010. 75 Fed. Reg. at 48,784. This notification, however, must be submitted to EPA by no later than January 1, 2011 or by the end of the approved use of BMM, whichever is earlier, with a final request to be filed no later than February 15, 2011. Id. at 48,785. Here the timing creates a gap during which some sources will be operating with only BMM even though EPA has made no determination that such continued use is warranted. For example, a source that obtained an initial extension to use BMM until September 30, 2010 would submit its request on October 1, then enjoy an additional three months before it even has to lay out its full case for an extension in mid-February 2011. Moreover, such a source would have until July 1, 2011 to actually install measurement devices – apparently even if the Administrator eventually denies the extension request. See id. at proposed (j)(6).

It is not clear that such delays and additional time to make extension requests are warranted. Indeed, a significant underlying premise of and justification for the proposal is that companies have patterns of planned outages that they schedule many years in advance. The company even has to submit its historic shutdown information for the unit in its extension request. See id. at proposed (j)(4)(iv) (request must include “the date of the three most recent shutdowns for each relevant process equipment or unit, the frequency of shutdowns for each relevant process equipment or unit, and the date of the next planned process equipment or unit shutdown.”) Thus, the vast majority of, if not all, sources will know in well in-advance of the expiration of their first BMM extensions (not to mention in advance of February 15, 2011) that they need additional leeway. Notably, EPA is proposing a third extension request deadline several months in advance of the December 31, 2013 second tier installation deadline. See id. at proposed (j)(7) (request to use BMM after December 31, 2013 must be submitted by June 1, 2013). EPA should consider advancing the deadlines for second extension requests and/or eliminating any gaps created by the timing of these deadlines.

Response: Please see response to comment EPA-HQ-OAR-2008-0508-2370.1, excerpt 1 and Section II.A of the preamble for the final rule amendments for the response to this comment.

EPA considered, but decided not to advance the deadlines for the notification to request BMM for 2011. Facilities that would have required a shutdown to install the necessary monitoring equipment, but did not have a shutdown scheduled during 2010, most likely have already asked for BMM through the end of 2010, if not longer. These initial BMM requests were approved only through December 31, 2010. Given the timing of this rulemaking, and the need to ensure that facilities with BMM would not have a period during which their BMM approval would lapse, we determined that it was necessary to provide facilities the ability to notify EPA by January 1, 2011 and essentially grant them BMM until July 1, 2011 (and later if approved). As a practical matter, this automatic BMM through June 30, 2011 is necessary to give EPA sufficient time to evaluate the applications, while providing sufficient certainty for the reporters on their compliance obligations. If the automatic extension period is not long enough to allow EPA to evaluate the requests and inform a facility whether its request was approved well in advance of the expiration of the automatic extension, many of these facilities may feel compelled to undertake an unscheduled shutdown or a hot tap because they could not be assured of getting

the extension approved by EPA in time. This is the very result we are trying to avoid with the extended BMM process.

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2008-0508-2383.1

Comment Excerpt Number: 2

Comment: The Clean Air Task Force, Natural Resources Defense Council, and Sierra Club (collectively, CATF) argues against the proposed extension of deadlines for installation of meters and other measurement devices, suggesting that such extensions may not be warranted. While the American Petroleum Institute (API) and NPRA understand the desire to have monitored data as soon as possible, the short implementation schedule in the final rule would present compliance challenges that go beyond mere inconveniences. As demonstrated by API and NPRA's early submissions, allowing extensions under certain limited conditions would alleviate potential safety risks that would otherwise be necessitated by dangerous and delicate "hot-tapping" to install required monitoring equipment before a scheduled shut down. The Settlement Agreement's revisions to 40 C.F.R. §98.3(j) would allow the owner or operator of a regulated facility under certain limited conditions to request EPA approval for additional time to continue using best available monitoring methods if an unscheduled shut down or "hot tap" would be necessary to install certain monitoring equipment. The risk associated with hot-tapping should be avoided whenever possible and the proposed Settlement Agreement would achieve that goal.

Response: We have finalized the post 2010 BMM process, as proposed. Please see Section II.A of the preamble for the final rule amendments for the response to this comment.

Definition of agricultural byproducts

Commenter Name: Craig Holt Segall

Commenter Affiliation: Sierra Club Environmental Law Program et. al

Document Control Number: EPA-HQ-OAR-2008-0508-2398.1

Comment Excerpt Number: 10

Commenter Name: Helen D. Silver

Commenter Affiliation: Clean Air Task Force et. al

Document Control Number: EPA-HQ-OAR-2008-0508-2403.1

Comment Excerpt Number: 2

These two commenters submitted identical comments on this subject.

Comment: Additional Definitions Related to Biomass. We support EPA's clarification of the definitions of "agricultural byproducts," "solid byproducts," and "wood residuals." As we have stated numerous times, an accurate GHG emissions inventory is essential. The accuracy of the

default CO₂ emissions factors and high heat values (“HHV”) provided for in the regulation will play a large part in achieving this objective. As EPA gains experience with the implementation of this rule and more comprehensive information about the sources of GHG emissions, we urge EPA to review these existing values for accuracy and to provide more specific values for fuels within those categories. For instance, when and if EPA is able to do so, it should provide specific values for biomass feedstocks that would otherwise fall within the umbrella categories of “agricultural byproducts,” “solid byproducts,” and “wood residuals.”

Response: We thank the commenter for the input. As policies and programs evolve and/or particular calculation or monitoring equipment improves EPA plans to evaluate whether or not to update the methodologies in this rule.

Definition of municipal solid waste (MSW)

Commenter Name: John R. "Doc" Holladay

Commenter Affiliation: Local Government Coalition for Renewable Energy

Document Control Number: EPA-HQ-OAR-2008-0508-2378.1

Comment Excerpt Number: 1 and 2

Comment: EPA’s October 2009 GHG Reporting Rule defines MSW as “solid phase household, commercial/retail, and/or institutional waste, such as, but not limited to, yard waste and refuse.” See 40 C.F.R. § 98.6 (Definitions), 74 Fed. Reg. at 56389/2 (the virgule [“/”] identifies the column or columns to which we are referring). EPA’s August 11 rulemaking proposal notes that various commenters critiqued that definition as insufficient to determine whether certain types of waste constitute MSW. See Mandatory Reporting of Greenhouse Gases, 75 Fed. Reg. at 48754/2-3. On that basis, EPA proposes to amend the GHG Reporting Rule’s definition of MSW to parallel the definition in Subpart Ea of the NSPS for MWC facilities, *supra*, 40 C.F.R. § 60.51a. Specifically, EPA proposes to define MSW as

solid phase household, commercial/retail, and/or institutional waste. Household waste includes material discarded by single and multiple residential dwellings, hotels, motels, and other similar permanent or temporary housing establishments or facilities. Commercial/retail waste includes material discarded by stores, offices, restaurants, warehouses, non-manufacturing activities at industrial facilities, and other similar establishments or facilities. Institutional waste includes material discarded by schools, nonmedical waste discarded by hospitals, material discarded by non-manufacturing activities at prisons and government facilities, and material discarded by other similar establishments or facilities. Household, commercial/retail, and institutional waste does not include used oil, wood p[al]lets, construction, renovation, and demolition wastes (which includes, but is not limited to, railroad ties and telephone poles), clean wood, industrial process or manufacturing wastes, medical waste, or motor vehicles (including motor vehicle parts or vehicle fluff). Household, commercial/retail, and institutional wastes include yard waste, refuse-derived fuel, and motor vehicle maintenance materials, limited to vehicle batteries and tires, except where a single waste stream consisting of tires is combusted in a unit.

See Mandatory Reporting of Greenhouse Gases, 75 Fed. Reg. at 48785-86 (text of proposed 40 C.F.R. § 98.6, Definitions).

As already indicated, this new definition would exclude a number of materials such as clean wood and wood pallets, construction and demolition waste, used motor oil and a broad range of motor vehicle maintenance parts (the latter can range from windshield wiper blades to filters, headlamps and other lighting and electrical parts, etc.). [Footnote: Although on an average basis the quantities of clean wood, wood pallets, construction and demolition debris, etc., processed by a given municipal waste combustion facility are limited, periodically more significant quantities of such materials will be delivered to WTE facilities for processing.] Those materials are unavoidable in MSW, particularly residential waste, as EPA has long recognized. For example, EPA's website notes that at least 10 percent of motorists dispose of used motor oil in their household waste. Similarly, EPA's annual overview of MSW in the United States indicates that 6.6 percent of MSW is clean wood, primarily from wood packaging, including wood pallets, and only a small portion of that wood waste (about 15 percent of the 6.6 percent) is recovered for recycling. Similarly, EPA has acknowledged that construction and demolition debris is a significant portion of the overall "municipal solid waste stream." [Footnote: 4 U.S. Environmental Protection Agency, What's in a Building- Composition Analysis of C&D Debris, <http://www.epa.gov/region09/waste/solid/pdf/cd1.pdf>.]

As noted above, EPA's August 11 proposal to amend the GHG Reporting Rule explains that the proposed definition of MSW mirrors the definition in the NSPS for municipal waste combustion units and has the same exclusions. The administrative record for the NSPS shows, however, that the exclusions from the NSPS definition were not made due to any assumption that clean wood, wood pallets, used motor oil, small quantities of used tires, etc., are absent from MSW. Rather, those materials were excluded from the NSPS definition because stationary sources that generate power (or otherwise recover energy) from homogeneous streams of such materials successfully sought to be excluded from the rigorous air emission limitations for municipal waste combustors under the NSPS (as well as the related Emission Guidelines in 40 C.F.R. § 60.50b, et seq.).

EPA has addressed this point on several occasions in connection with the NSPS and Emission Guidelines and various amendments to each. For example, in amendments to the NSPS and Emission Guidelines proposed in 1994, EPA explained as follows:

[W]aste-fuel power generation facilities that combust a single-item waste stream of tires, fuel derived solely from tires, or used oil would be subject only to an initial notification of construction and would not be subject to any other provisions in today's proposal. This exclusion is unchanged from the NSPS promulgated on February 11, 1991.

See Standards of Performance for New Stationary Sources: Municipal Waste Combustors, Proposed Rule and Notice of Public Hearing, 59 Fed. Reg. 48198, 48212/2 (Sept. 20, 1994). EPA elaborated on its policy position in connection with combustion of used tires, explaining that although "[t]ires are considered to be MSW," "combustors that fire 100 percent tires . . . or tire-derived fuel with other non-MSW fuels[] are specifically excluded from the combustor standards." See Standards of Performance for New Stationary Sources and Final Emission

Guidelines; Final Rules, 56 Fed. Reg. 5488, 5495/3 (Feb. 11, 1991); see also *id.* at 5496/1 (“[T]ires are a national problem and since few options exist for their disposal, the Agency does not want to take any premature action that could discourage projects for the combustion of tires and, therefore, dedicated tire combustion facilities are not regulated under this NSPS for MWCs. However, combustors that do not fire 100 percent tires or tire-derived fuel, but co-fire tires or tire-derived fuel with MSW, would be covered under this NSPS if the combustor meets the other MWC applicability requirements of the standards.”).

EPA further addressed this subject in connection with 1995 amendments to the NSPS and Emission Guidelines. In particular, EPA explained that although clean wood had previously been included in the definition of MSW, the agency changed course and decided that the rigorous air emission limits it applied to municipal waste combustion units were not necessary for single-stream combustion of clean wood. EPA addressed this point as follows:

Under the proposed standards, clean wood was included in the definition of MSW. Several commenters disagreed with this decision to cover clean wood under the MWC standards. Under the final rule, clean wood is not considered to be MSW. . . . Clean wood is predominantly an agricultural, industrial, or other non-municipal solid waste; regulation of the combustion of these types of wastes is currently being addressed under a separate rulemaking.

Standards of Performance for New Stationary Sources and Emission Guidelines for Existing Sources, Final Rule, 60 Fed. Reg. 65387, 65395/2 (Dec. 19, 1995).

In short, the rulemaking record for the NSPS and Emission Guidelines for municipal waste combustion facilities demonstrates that the purpose of the above-described exclusions from the definition of MSW was to exempt certain types of combustion facilities from the NSPS and Emission Guidelines and not to preclude combustion of such materials by the WTE facilities that are the intended focus of the emission limitations and other standards that underlie the NSPS and Emission Guidelines. In that regard, EPA has consistently recognized that clean wood, other construction and demolition waste, used oil, etc., are present – and, in fact, unavoidable – in MSW. The latter has direct implications under the GHG Monitoring Rule, specifically, the substantially more costly and burdensome GHG monitoring that will be required for WTE facilities as a direct result of the proposed new definition of MSW.

The Proposed MSW Definition Would Force WTE Facilities to Tier 4 Monitoring. Tier 4 is the most demanding monitoring protocol under the GHG Reporting Rule. To the extent Tier 4 monitoring is required for WTE facilities, it will often require costly upgrades of existing CEMS to accommodate GHG monitoring. To be sure, EPA’s April 2009 proposal for the GHG Reporting Rule had expressly contemplated either Tier 2 or Tier 4 monitoring for WTE facilities. See 74 Fed. Reg. 16448, 16481, Table C-1 (April 10, 2009). However, in response to the concern of MWC owners-operators that the 250 TPD threshold would disproportionately burden MWC facilities, see 75 Fed. Reg. at 48757/1-2, EPA’s August 11 proposal to amend the GHG Reporting Rule would increase from 250 tons per day (“TPD”) to 600 TPD the threshold at which Tier 4 monitoring applies to municipal waste combustion units. Given the fact that the municipal waste combustion units at most WTE facilities are below the 600 TPD threshold, the

change to the 600 TPD threshold is intended to expand substantially the opportunity for WTE facilities to use Tier 2 monitoring. Importantly, Tier 2 monitoring does not require CEMS for carbon dioxide and instead calculates carbon dioxide emissions based on fuel use, higher heating value and fuel-specific emissions factors. See 75 Fed. Reg. at 48757/1-2. But the expanded use of Tier 2 monitoring that EPA intended for WTE facilities will largely be nullified by the proposed new definition of MSW, which would generally exclude the fuel combusted by WTE facilities from the GHG Reporting Rule's definition of MSW. As a consequence, WTE facilities would be forced to Tier 4 monitoring (albeit with some cases where Tier 3 monitoring could apply).

In that regard, WTE facilities are generally subject to the GHG reporting rule due to CO₂e emissions above the rule's annual threshold of 25,000 metric tons and aggregate maximum rated heat input capacity of 30 mmBtu/hour or more. See 40 C.F.R. § 98.2(a)(3). The unintended mandate for Tier 4 monitoring is evident from review of 40 C.F.R. § 98.33(b):

Tier 1 – Tier 1 does not appear to be an option because, as relevant here, it is limited to sources that combust “any fuel listed in Table C-1 of this subpart,” and although MSW is listed in Table C-1, the fuel combusted by WTE facilities generally does not meet the GHG Reporting Rule's proposed definition of MSW (for the same reason, Tier 1 is also precluded for small MSW combustors that do not produce steam).

Tier 2 – Tier 2 is intended to apply broadly to WTE facilities. See 40 C.F.R. § 98.33(b)(2)(iii) (stating that Tier 2 applies to “MSW in a unit of any size that produces steam[] if the use of Tier 4 is not required”). Once again, however, it appears that Tier 2 would generally not apply to WTE facilities because the fuel they process would generally not meet the GHG Reporting Rule's proposed definition of MSW.

Tier 3 – Similarly, Tier 3 is not an option for WTE facilities because it is primarily limited to facilities that combust fuels listed in Table C-1. See 40 C.F.R. § 98.33(b)(3)(i) and (ii). Although Tier 3 can be used in some circumstances for facilities that combust a fuel not listed in Table C-1, that alternative is limited to units with maximum rated heat input capacity greater than 250 mmBtu/hour, and the municipal waste combustion units at many WTE facilities have maximum rated heat input capacity below that level.

Tier 4 – Finally, due to the unavailability of Tiers 1-3, WTE facilities will default to Tier 4, which is the fallback “for a unit of any size, combusting any type of fuel.” 40 C.F.R. § 98.33(b)(4)(i).

In sum, the definition of MSW in the proposed GHG Reporting Rule amendments is such that the typical fuel for essentially all municipal waste combustors and WTE facilities does not appear to qualify as MSW, which will force those facilities to more costly and burdensome Tier 4 monitoring. That does not appear to have been the result intended by EPA, particularly given the Agency's acknowledgement in its August 11 rulemaking proposal that expanded availability of Tier 2 monitoring for municipal waste combustors will provide WTE facilities with “comparable monitoring thresholds and conditions as other general stationary combustion units.” See 75 Fed. Reg. at 48757/2. Accordingly, EPA should either adhere to the definition of MSW

under the current terms of the GHG Reporting Rule or adopt a revised definition which recognizes that MSW, in particular residential waste and similar waste streams from commercial and institutional establishments, will necessarily include materials such as clean wood and wood pallets, construction and demolition waste, etc.

Response: Please see Section II.F of the preamble for the final rule amendments for the response to this comment. We did not intend to push municipal waste combustors into use of higher tiers through the change in the definition of municipal solid waste. The final rule clarifies that “insofar as there is separate collection, processing and disposal of industrial source waste streams consisting of used oil, wood pallets, construction, renovation, and demolition wastes (which includes, but is not limited to, railroad ties and telephone poles), clean wood, plastics, industrial process or manufacturing wastes, medical waste, motor vehicle parts or vehicle fluff, or used tires that do not contain hazardous waste identified or listed under 42 U.S.C. §6921, such wastes are not municipal solid waste. However, such wastes qualify as municipal solid waste where they are collected with other municipal solid waste or are otherwise combined with other municipal solid waste for processing and/or disposal.”

Commenter Name: Edward W. Repa

Commenter Affiliation: National Solid Wastes Management Association (NSWMA)

Document Control Number: EPA-HQ-OAR-2008-0508-2379.1

Comment Excerpt Number: 3

Comment: The definition of MSW in Section 98.6 is yet again another definition supplied by EPA. EPA has defined MSW in its Fact and Figures Documents [Footnote: U.S. Environmental Protection Agency. <http://www.epa.gov/osw/nonhaz/municipal/msw99.htm>.] of various years as:

“Municipal solid waste (MSW) includes wastes such as durable goods, nondurable goods, containers and packaging, food scraps, yard trimmings, and miscellaneous inorganic wastes from residential, commercial, institutional, and industrial sources. Examples of waste from these categories include appliances, automobile tires, newspapers, clothing, boxes, disposable tableware, office and classroom paper, wood pallets, and cafeteria wastes. MSW does not include wastes from other sources, such as construction and demolition debris, automobile bodies, municipal sludges, combustion ash, and industrial process wastes that might also be disposed in municipal waste landfills or incinerators” and

“MSW—otherwise known as trash or garbage—consists of everyday items such as product packaging, grass clippings, furniture, clothing, bottles, food scraps, newspapers, appliances, and batteries. Not included are materials that also may be disposed in landfills but are not generally considered MSW, such as construction and demolition materials, municipal wastewater treatment sludges, and non-hazardous industrial wastes.”

NSWMA believes that EPA should have and use a standard definition of MSW in all documents and rules. NSWMA is willing to assist EPA in developing this definition to ensure consistency between various EPA rules and documents.

Response: We have finalized a definition of municipal solid waste that is similar to that used in the subpart Ea of the NSPS regulations. Please see Section II.F of the preamble for the final rule amendments for the response to this comment.

Although consistency is desirable, it is beyond the scope of the GHGRP to try and make all of the definitions of MSW in all EPA regulations and guidance documents the same. We proposed a substantive definition taken from Subpart Ea, which specifically regulates large MWC units. In response to comments received, the final rule clarifies when certain materials are either included in or excluded from the definition. The adjustments made to the definition are consistent with the regulatory history of Subpart Ea.

Commenter Name: Rhea Hale

Commenter Affiliation: American Forest & Paper Association (AF&PA)

Document Control Number: EPA-HQ-OAR-2008-0508-2382.1

Comment Excerpt Number: 4

Comment: The American Forest & Paper Association (AF&PA) requests the following edits (see the phrases in square brackets) to the proposed definition of municipal solid waste: Municipal solid waste or MSW means solid phase household, commercial/retail, and/or institutional waste. Household waste includes material discarded by single and multiple residential dwellings, hotels, motels, and other similar permanent or temporary housing establishments or facilities. Commercial/retail waste includes material discarded by stores, offices, restaurants, warehouses, nonmanufacturing activities at industrial facilities, and other similar establishments or facilities. Institutional waste includes material discarded by schools, nonmedical waste discarded by hospitals, material discarded by non-manufacturing activities at prisons and government facilities, and material discarded by other similar establishments or facilities. Household, commercial/retail, and institutional waste does not include used oil, wood pellets, construction, renovation, and demolition wastes (which includes, but is not limited to, railroad ties and telephone poles), [paper that is commonly recycled,] clean wood, industrial process or manufacturing wastes, medical waste, or motor vehicles (including motor vehicle parts or vehicle fluff). Household, commercial/retail, and institutional wastes include yard waste, refuse-derived fuel, and motor vehicle maintenance materials, limited to vehicle batteries and tires, except where a single waste stream consisting of tires is combusted in a unit.

Response: The exclusion of “paper” was an oversight and should have been included in the definition. Therefore, we have incorporated the commenter's suggestion. The definition of MSW in the final rule specifies that when paper is separately collected, processed, and disposed of (such as by recycling), it is not considered to be MSW.

Commenter Name: Ted Michaels

Commenter Affiliation: Energy Recovery Council (ERC)
Document Control Number: EPA-HQ-OAR-2008-0508-2393.1
Comment Excerpt Number: 7

Comment: EPA has proposed to amend the definition of “municipal solid waste” in the MRR to closely match the definition in Subpart Ea of the NSPS regulations (40 CFR 60.51a). However, strict application of the NSPS definition of MSW in the MRR would mean that the presence of any exempted material could trigger Tier 4 reporting, even for units rated below 600 tons per day.

The NSPS definition includes a list of excluded materials from the categories of household, commercial/retail, and institutional waste including used oil, wood pellets, construction, renovation, and demolition wastes (which includes, but is not limited to, railroad ties and telephone poles), clean wood, industrial process or manufacturing wastes, medical waste, or motor vehicles (including motor vehicle parts or vehicle fluff). These materials can be present in municipal solid waste streams to varying degrees. The material exclusions contained in the NSPS definition was intended to delineate a group of materials that would be regulated under NSPS source categories separate from municipal waste combustors when combusted in a single stream, not to imply that these materials would not be present to some extent in municipal solid waste.

As applied in the GHG MRR, however, exclusion of these materials could lead to the unintended consequence of reintroducing Tier 4 reporting requirements for units below the 600 tons per day threshold. The proposed language of the MRR Corrections states that Tier 2 can be used for MSW, as long as Tier 4 is not required (units above 600 tons per day). The presence of excluded materials in a waste stream could cause it to be a material other than “municipal solid waste” for the purposes of the MRR and therefore unable to report using Tier 2, regardless of the rated capacity of the unit.

We strongly recommend that the EPA return to the definition of “municipal solid waste” as promulgated in the MRR published in the Federal Register on October 30, 2009 or specifically recognize that facilities permitted as municipal waste combustors under the NSPS requirements of 40 CFR 60 combust “municipal solid waste.”

Response: Please see response to comment EPA-HQ-OAR-2008-0508-2378.1, excerpt 1 and 2 for the response to this comment.

Commenter Name: Brian Gasiorowski
Commenter Affiliation: Lafarge North America
Document Control Number: EPA-HQ-OAR-2008-0508-2401.1
Comment Excerpt Number: 3

Commenter Name: Bryan Brendle
Commenter Affiliation: Portland Cement Association
Document Control Number: EPA-HQ-OAR-2008-0508-2399.1
Comment Excerpt Number: 9

These two commenters submitted identical comments on this subject.

Comment: Municipal Solid Waste. We propose that EPA’s proposed municipal solid waste definition (EPA, August 11, 2010) be modified further by adding the phrase "recovered or separated plastics" as shown in bold italic type.

Municipal solid waste or MSW means solid phase household, commercial/retail, and/or institutional waste. Household waste includes material discarded by single and multiple residential dwellings, hotels, motels, and other similar permanent or temporary housing establishments or facilities. Commercial/retail waste includes material discarded by stores, offices, restaurants, warehouses, non-manufacturing activities at industrial facilities, and other similar establishments or facilities. Institutional waste includes material discarded by schools, nonmedical waste discarded by hospitals, material discarded by non-manufacturing activities at prisons and government facilities, and material discarded by other similar establishments or facilities. Household, commercial/retail, and institutional waste does not include used oil, wood pellets, ***recovered or separated plastics***, construction, renovation, and demolition wastes (which includes, but is not limited to, railroad ties and telephone poles), clean wood, industrial process or manufacturing wastes, medical waste, or motor vehicles (including motor vehicle parts or vehicle fluff). Household, commercial/retail, and institutional wastes include yard waste, refuse-derived fuel, and motor vehicle maintenance materials, limited to vehicle batteries and tires, except where a single waste stream consisting of tires is combusted in a unit.

Response: Please see Section II.G of the preamble for the final rule amendments for the response to this comment.

Definition of natural gas

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2008-0508-2383.1

Comment Excerpt Number: 5

Comment: The amendments include a revision to the definition of natural gas to indicate that it is composed of at least 70% CH₄ by volume or has a HHV between 910 and 1150 Btu/scf. This revision conflicts with the remainder of the definition, as the range of HHV values represents a narrow range of pipeline quality natural gas, and excludes most field quality natural gas. This poses significant issues when considering the use of the term natural gas in the context of Subpart W. This revision also negates the change to Table C-1, where “pipeline” is removed from the description of natural gas. API requests that EPA maintain the definition of natural gas from the October 30, 2009 rule, with the exception of removing the last sentence. The revised definition would read:

“Natural gas means a naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the earth’s surface, of which its constituents include, but are not limited to, methane, heavier hydrocarbons, and carbon dioxide. Natural gas may be field quality (which varies widely) or pipeline quality.”

Response: EPA decided to remove the specifications regarding a minimum methane content and a range of high heating values in the definition of natural gas. Please refer to Section II.F.2 of the preamble to the final rule amendments for the rationale for removing these specifications. We decided not to use the exact definition provided by the commenter because adding the term “which varies widely” does not increase the utility of the definition after we have removed the specifications for HHV range and minimum methane content. The final definition of natural gas is also consistent with the removal of “pipeline” in Table C-1.

Commenter Name: Jeff Applekamp

Commenter Affiliation: Gas Processors Association (GPA)

Document Control Number: EPA-HQ-OAR-2008-0508-2402.1

Comment Excerpt Number: 5

Comment: 98.6 Definition of Natural Gas. EPA is proposing to revise the definition of natural gas under 98.6 to indicate that it is composed of at least 70% methane (CH₄) by volume or has a high heating value (“HHV”) between 910 and 1150 Btu/scf. This revision poses significant issues in meeting the reporting timeline of the GHG RP. There are many different types of gaseous streams combusted at facilities operated by GPA members companies. The change in the definition of “natural gas” forces GPA members to revisit each gas stream to determine if it fits within the new definition of natural gas in terms of the carbon content or heating value range, and if so, GPA members must determine if the change prompts modifications to the emission estimation methodologies required by the rule. In addition, this revision conflicts with the remainder of the definition, as the range of HHV values proposed represents a narrow range of pipeline quality natural gas, and excludes most field quality natural gas. This revision also negates the change to Table C-1, where “pipeline” is removed from the description of natural gas. GPA requests that EPA maintain the definition of natural gas from the October 30, 2009 rule.

Response: Please see response to comment EPA-HQ-OAR-2008-0508-2383.1, excerpt 5 for the response to this comment.

Definition of waste oil

Commenter Name: Kimberly A. Hibbard

Commenter Affiliation: S.D. Warren Company - Somerset Operations

Document Control Number: EPA-HQ-OAR-2008-0508-2404

Comment Excerpt Number: 1

Comment: The proposed changes to the regulation include the listing of waste oil in Table C-1 of 40 CFR Part 98 Subpart C General Stationary Fuel Combustion Sources. Once waste oil is listed in Table C-1, Section 98.33(b)(3) and (4) would require a source that burns waste oil in a boiler with a maximum rated heat input capacity greater than 250 MMBtu/hr to calculate greenhouse gas emissions according to Tier 3 or Tier 4. The Somerset Mill has no issue with calculating the greenhouse gas emissions from waste oil. However, Section 98.34 sets forth the QA/QC requirements for each Tier. For the use of Tier 3, pursuant to 98.34(b)(3) a carbon content analysis of waste oil would be required. It is unclear by the proposed definition of waste oil if it would be considered "fuel oil" in 98.34(b)(3)(ii)(B) requiring an analysis per lot or "other liquid fuels other than fuel oil" in 98.34(b)(3)(ii)(C) requiring one analysis per calendar quarter. S .D. Warren adds both onsite generated and purchased waste oil directly into the mill's No .6 fuel oil main supply tank. The onsite generated waste oil is added in small volumes at a time (approximately 700 gallons or less). If waste oil is considered fuel oil, would a carbon content analysis be required for each small volume of onsite generated waste oil added to the No. 6 oil tank? Additionally, offsite waste oil is received in relatively small volumes from commercial retailers. The cost associated with the carbon content analysis for both onsite and offsite generated waste oil seems excessive given the small quantity used by the Somerset Mill and the relatively small impact on GHG emissions.

Response: The term "waste oil" has been replaced with the term "used oil" in the final rule amendments (see Section II.F of the preamble to the final rule amendments.) Used oil consists primarily of used lubricating and automotive oils (e.g., used motor oil, transmission oil, hydraulic fluids, brake fluid, industrial engine oils, metalworking oils, process oils, industrial grease, etc). EPA's long-standing position that on-specification used oil is essentially equivalent to virgin fuel oil. Therefore, used oil is considered to be fuel oil.

For a unit that has a heat input capacity greater than 250 mmBtu/hr and combusts fuels in Table C-1 other than natural gas and distillate oil, the use of Tier 3 is triggered. For the specific case cited by the commenter, if the used oil and the No. 6 oil are treated as separate fuels, each one would have to be analyzed for carbon content at the frequency specified in §98.34(b)(3)(ii)(B), and the quantity of each fuel would have to be separately measured, using either calibrated flow meters or tank drop measurements, as applicable. However, in accordance with §98.34(b)(3)(ii)(F) and the term "Fuel" in Equation C-4, if the mixture (blend) of No. 6 oil and used oil is considered to be the "fuel type", carbon content sampling would be required only once per quarter, and tank drop measurements could be used to quantify the amount of blended fuel combusted.

Please see also the response to the subpart C comment EPA-HQ-OAR-2008-0508-2404, excerpt 2, under "Tier 3 Applicability".

Commenter Name: Sean M. O'Keefe

Commenter Affiliation: Alexander & Baldwin, Inc.

Document Control Number: EPA-HQ-OAR-2008-0508-2380.1

Comment Excerpt Number: 4

Comment: References to "waste oil" should be changed to "used oil". EPA has proposed to add a definition of "waste oil" to section 98.6 of the reporting rule and to add a higher heat value (HHV) and default CO₂ emission factor for waste oil to Table C-I. In a separate rulemaking (Docket Number EPA-HQ-RCRA-2008-0329, Identification of Non-Hazardous Secondary Materials That Are Solid Waste; Proposed Rule), EPA is considering, among other things, whether used oil should be classified as a solid waste. In that rulemaking, EPA has proposed not to classify on-specification used oil as a solid waste but instead to consider it a "traditional fuel". This conclusion is based on the EPA's long-standing position that on-specification used oil is essentially equivalent to virgin fuel oil. A&B believes that use of the term "waste oil" in the GHG Reporting Rule suggests that EPA considers all oil meeting the proposed definition of "waste oil", including on-specification used oil, to be a waste, which is inconsistent with EPA's position as expressed in the proposed solid waste rule. While A&B recognizes that the solid waste rule has been proposed under the RCRA program, we note that whether or not certain materials, including used oil, are classified as solid waste under this rule will determine whether facilities which burn these materials will be regulated as boilers or as commercial and industrial solid waste incinerators under the Clean Air Act. For consistency with other regulatory programs, therefore, A&B recommends that EPA use the term "used oil" rather than "waste oil" in the GHG Reporting Rule.

Response: The term "waste oil" has been replaced with the term "used oil" in the final rule amendments. Please see Section II.F of the preamble to the final rule amendments and response to comment EPA-HQ-OAR-2008-0508-2404, excerpt 1 for additional information in response to this comment.

Commenter Name: Bryan Brendle
Commenter Affiliation: Portland Cement Association
Document Control Number: EPA-HQ-OAR-2008-0508-2399.1
Comment Excerpt Number: 5

Comment: "Waste oil" is proposed to be added to the list of petroleum products in Table C-1, and an accompanying definition added to 40 CFR 98.6. PCA supports broader definitions. PCA believes these changes add flexibility.

Response: The term "waste oil" has been replaced with the term "used oil" in the final rule amendments. Please see Section II.F of the preamble for the final rule amendments for the response to this comment.

Definition of wood residuals

Commenter Name: Stephen E. Woock
Commenter Affiliation: Weyerhaeuser Company
Document Control Number: EPA-HQ-OAR-2008-0508-2375.1
Comment Excerpt Number: 2

Comment: The proposed definition of Wood Residuals needs to be expanded. The final rule has a definition of “biomass” in Subpart A at §98.6. That definition is generally broad enough to accommodate valuable sources of biogenic fuels in the U.S. Because the biomass definition includes the phrase “... including products, by-products, residues and waste from agriculture, forestry and related industries,” this definition, in our understanding, includes among other woody biomass resources the wood residuals from downstream wood products manufacturing as well as wood residuals from the initial processing of timber at forest products industry mills. The original rule also has the terms “Wood and Wood Residuals,” along with “Agricultural Byproducts,” “Peat” and “Solid Byproducts” as listed, specific solid biomass fuel types in Table C-1 to Subpart C. Table C-1 provides “Default CO₂ Emission Factors and High Heat Values for Various Types of Fuel,” which are used in various emissions calculations for those employing either the Tier 1 or Tier 2 calculation methods. However, none of these specified solid biomass types are defined in the original rule, though default CO₂ emission factors and High Heat Values were provided for each.

So now EPA is providing definitions for three of the four terms: “Wood Residuals,” “Agricultural Byproducts,” and “Solid Byproducts.” EPA explains in the preamble to the proposed rule that it is proposing to add definitions of the terms to §98.6 “...due to the large number of questions received requesting clarification of the definition of these terms.” Preamble at pg 48754. Further, EPA indicates it has drawn the proposed definitions “...based on the results of an Internet search and IPCC inventory guidelines.”

For Subpart C (General Stationary Fuel Combustion Sources) sources burning biomass we are concerned that the newly proposed Wood Residuals definition is defined with so much specificity that it is unclear whether biomass residuals from downstream manufacturing, such as wood panel plants and engineered wood products mills are covered by the default values Table C-1 provides. To ensure those residuals are included we suggest the following modification (underlined language) to the proposed definition:

Wood residuals means wood waste recovered from three principal sources: Municipal solid waste (MSW); construction and demolition debris; and primary timber processing. Wood residuals recovered from MSW include wooden furniture, cabinets, pallets and containers, scrap lumber (from sources other than construction and demolition activities), and urban tree and landscape residues. Wood residuals from construction and demolition debris originate from the construction, repair, remodeling and demolition of houses and non-residential structures. Wood residuals from primary timber processing include bark, sawmill slabs and edgings, sawdust, and peeler log cores. Other sources of wood residuals include, but are not limited to, railroad ties, telephone and utility poles, pier and dock timbers, wastewater process sludge from paper mills, trim, sander dust and sawdust from wood products manufacturing including resinated wood product residuals, and logging residues.

Response: This change has been made to the definition. Please see Section II.F of the preamble for the final rule amendments for the response to this comment.

Commenter Name: Rhea Hale

Commenter Affiliation: American Forest & Paper Association (AF&PA)

Document Control Number: EPA-HQ-OAR-2008-0508-2382.1

Comment Excerpt Number: 3

Comment: EPA requested comment on whether it is appropriate to apply emissions factors for wood residuals to wastewater treatment sludges from pulp and paper mills. The American Forest & Paper Association (AF&PA) agrees that it is appropriate for wastewater treatment sludges to be included in the revised definition of wood and wood residuals and to apply the same emissions factors for wood residuals to wastewater treatment sludges. AF&PA requests the following edits (see the phrases in square brackets) to the proposed definition of wood residuals:

Wood residuals means [materials] recovered from three principal sources: municipal solid waste (MSW); construction and demolition debris; and primary timber processing. Wood residuals recovered from MSW include wooden furniture, cabinets, pallets and containers, scrap lumber (from sources other than construction and demolition activities), and urban tree and landscape residues. Wood residuals from construction and demolition debris originate from the construction, repair, remodeling and demolition of houses and non-residential structures. Wood residuals from primary timber processing include bark, sawmill slabs and edgings, sawdust, and peeler log cores. Other sources of wood residuals include, but are not limited to, railroad ties, telephone and utility poles, pier and dock timbers, wastewater process sludge from paper mills, [trim, sander dust and sawdust from wood products manufacturing including resinated wood product residuals,] and logging residues.

Response: This change has been made to the definition. Please see Section II.F of the preamble for the final rule amendments for the response to this comment.

Other definitions

Commenter Name: Kerry Kelly

Commenter Affiliation: Waste Management (WM)

Document Control Number: EPA-HQ-OAR-2008-0508-2360.1

Comment Excerpt Number: 1

Commenter Name: Ted Michaels

Commenter Affiliation: Energy Recovery Council (ERC)

Document Control Number: EPA-HQ-OAR-2008-0508-2393.1

Comment Excerpt Number: 1

These two commenters submitted identical comments on this subject.

Comment: EPA is proposing to correct the definition of “fossil fuel” and revert to the definition in the Proposed Rule, making the definition consistent with the definition used in the Clean Air

Act (CAA) New Source Performance Standards program. 74 Fed. Reg. 16621. We support the proposed correction as appropriate and necessary to ensure municipal solid waste (MSW) and tires are not inappropriately defined as fossil fuel. WM further supports the deletion of the definition of “fossil fuel-fired” that was not present in the Proposed Rule. We also note that by making these technical corrections and reverting to the definition of “fossil fuel” contained in the Proposed Rule, EPA has already afforded the public notice and ample opportunity to comment of the corrected definition.

Response: Please see Section II.F of the preamble for the final rule amendments for the response to this comment.

Commenter Name: John H. Skinner

Commenter Affiliation: Solid Waste Association of North America (SWANA)

Document Control Number: EPA-HQ-OAR-2008-0508-2397.1

Comment Excerpt Number: 1

Comment: The Solid Waste Association of North America (SWANA) agrees with EPA’s decision to revert the definition of “fossil fuel” back to that in the proposed rule. This definition is consistent with the definition of fossil fuel under the Clean Air Act’s New Source Performance Standards. Our concern over EPA’s new definition presented in the final version of the reporting rule is that it would classify municipal solid waste as “fossil fuel”, and reflected a significant change from the proposed rule by EPA without notice or the opportunity for public comment.

Response: We thank the commenter for the input. We have finalized the definition of fossil fuel as proposed. Please see Section II.F of the preamble for the final rule amendments for the response to this comment.

Commenter Name: Edward W. Repa

Commenter Affiliation: National Solid Wastes Management Association (NSWMA)

Document Control Number: EPA-HQ-OAR-2008-0508-2379.1

Comment Excerpt Number: 2

Comment: EPA is proposing that the definition of fossil fuel be returned to the initial proposed definition to provide clarity and make it consistent with other Clean Air Act sections. NSWMA agrees with this change because fossil fuel will not inappropriately include MSW and tires, which is the way fossil fuel was defined in the original Proposed Rule.

Response: We thank the commenter for the input. We have finalized the definition of fossil fuel as proposed. Please see Section II.F of the preamble for the final rule amendments for the response to this comment.

Commenter Name: Brian Gasiorowski

Commenter Affiliation: Lafarge North America

Document Control Number: EPA-HQ-OAR-2008-0508-2401.1
Comment Excerpt Number: 2

Commenter Name: Bryan Brendle
Commenter Affiliation: Portland Cement Association
Document Control Number: EPA-HQ-OAR-2008-0508-2399.1
Comment Excerpt Number: 8

These two commenters submitted identical comments on this subject.

Comment: 1. Proposed Definition Changes Plastics. We propose the following definition for plastics:

Plastics means plastic waste recovered or separated from three principal sources: municipal solid waste (MSW); construction and demolition debris; and waste from manufacturing and industrial processes. Plastics from MSW include non-recyclable or unwanted plastic parts, components, pieces, etc. from household, commercial or institutional sources - such as bottles, containers, bags, CD cases, sheeting, packaging, broken consumer goods, etc. Plastic from construction and demolition debris are typically piping, tubing, sheeting, coverings, containers, taping, etc. Plastics from manufacturing or industrial process include trimmings, cuttings, ends of rolls, off-spec or unsalable product or packaging, off-spec intermediate product or plastics residues from other recycling or separation processes.

Response: No change has been made as a result of this comment. We do not feel that it is necessary to define the term “plastics” in the final rule amendments since it is commonly understood and easily recognized whether a material or fuel source is plastic or non-plastic. The commenter is apparently concerned that plastic waste recovered from MSW and processed separately might be classified as MSW. The definition of MSW in the final rule makes it clear that this is not the case.

Commenter Name: Pamela A. Lacey
Commenter Affiliation: American Gas Association
Document Control Number: EPA-HQ-OAR-2008-0508-2394.1
Comment Excerpt Number: 2

Comment: The American Gas Association (AGA) supports EPA’s proposal to correct the confusing definition of “Mscf” in 40 C.F.R. 98.6 to say that the term means thousand standard cubic feet – which is the normal usage in the industry -- and not as incorrectly stated in the final rule, a million standard cubic feet. When combusted, 460,000 thousand standard cubic feet of natural gas could be expected to produce 25,000 tons of CO₂. While it was obvious that this was what EPA intended, the incorrect definition left our members confused. No doubt, the agency intended to say 460 million standard cubic feet – which is the same amount as 460,000 thousand standard cubic feet. We were among those who pointed out this discrepancy, and we appreciate your proposed correction. However, we note that while the preamble mentions this proposed

change, there appears to be no such provision in the actual proposed amendments to section 98.6. See 75 Fed. Reg. at 48754 and 48785-86. The final rule should include this change.

Response: The definition of "Mscf" was corrected in the amendments to 40 CFR part 98, subpart A, which were signed on October 7, 2010, and published in the Federal Register on October 28, 2010.

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2008-0508-2383.1

Comment Excerpt Number: 4

Comment: §98.6 Definition of mscf: EPA states in the preamble on pages 48753 and 48754 the intention to revise the definition of mscf from "million standard cubic feet" to "thousand standard cubic feet". API supports this clarification. However, the proposed regulatory text and redline version incorporating the August 11 revisions do not reflect the change. EPA should reflect the change in definition for mscf throughout the rule.

Response: The definition of "Mscf" was corrected in the amendments to 40 CFR part 98, subpart A, which were signed on October 7, 2010, and published in the Federal Register on October 28, 2010.

Commenter Name: Jeff Applekamp

Commenter Affiliation: Gas Processors Association (GPA)

Document Control Number: EPA-HQ-OAR-2008-0508-2402.1

Comment Excerpt Number: 4

Comment: §98.6 Definition of mscf: EPA states in the preamble on pages 48753 and 48754 the intention to revise the definition of mscf from "million standard cubic feet" to "thousand standard cubic feet". GPA supports this clarification. However, the proposed regulatory text and redline version incorporating the August 11 revisions do not reflect the change. GPA requests that EPA reflect the change in definition for Mscf throughout the rule

Response: The definition of "Mscf" was corrected in the amendments to 40 CFR part 98, subpart A, which were signed on October 7, 2010, and published in the Federal Register on October 28, 2010.

Commenter Name: Fiji George

Commenter Affiliation: El Paso Corporation

Document Control Number: EPA-HQ-OAR-2008-0508-2390.1

Comment Excerpt Number: 5

Comment Definition of Mscf. Current language: “*Mscf means million standard cubic feet.*” Proposed language with requested changes denoted by bold font: *Mscf means **thousand** standard cubic feet.* Justification: The proposed language corrects a technical error in the rule language.

Response: The definition of "Mscf" was corrected in the amendments to 40 CFR part 98, subpart A, which were signed on October 7, 2010, and published in the Federal Register on October 28, 2010.

Commenter Name: Anonymous

Commenter Affiliation: None

Document Control Number: EPA-HQ-OAR-2008-0508-2350

Comment Excerpt Number: 1

Comment: There are still errors in the updated proposed rule. The definition of Mscf is still defined as million standard cubic feet.

Response: The definition of "Mscf" was corrected in the amendments to 40 CFR part 98, subpart A, which were signed on October 7, 2010, and published in the Federal Register on October 28, 2010.

Commenter Name: Fiji George

Commenter Affiliation: El Paso Corporation

Document Control Number: EPA-HQ-OAR-2008-0508-2390.1

Comment Excerpt Number: 4

Comment: Definition of maximum rated heat input capacity: Current language: “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.” Proposed language with suggested changes in square brackets: “Maximum heat input capacity" means the [maximum heat value an affected source can combust on a steady state basis as determined by the physical and operational design and characteristics of the affected source. Maximum heat input capacity is expressed in millions of British Thermal Units (mmBtu) per unit of time. Maximum heat input capacity is the product of the gross caloric value (Higher Heating Value) of the fuel (expressed in Btu/mass) multiplied by the maximum fuel feed rate for the combustion device (expressed in mass of fuel/time)].” The proposed language is consistent with EPA’s response to a specific question posted by El Paso and provides clarification to the determination of the maximum heat input capacity values.

Response: No rule change has been made as a result of this comment. The changes to the definition suggested by the commenter are outside the scope of the specific amendments proposed for public comment in the Federal Register notice of August 11, 2010.

Commenter Name: Lisa Beal

Commenter Affiliation: Interstate Natural Gas Association of America (INGAA)

Document Control Number: EPA-HQ-OAR-2008-0508-2396.1

Comment Excerpt Number: 1

Comment: In Subpart A, §98.6, the definition for “maximum rated heat input capacity” is based solely on manufacturer specifications. For existing equipment, this definition may be inappropriate or difficult to address. For example, an existing combustion device could have been uprated or derated subsequent to initial installation, or manufacturer information may not be available for some existing equipment. In instances where a derate or uprate has occurred, as is commonly done to gas turbine ratings to account for site-specific ambient conditions, the heat input capacity may be included in a permit, and that capacity may differ from the manufacturer specifications. To avoid unnecessary confusion and also address the situation where manufacturer information is not readily available, the Interstate Natural Gas Association of America (INGAA) recommends revising the definition as follows (new text bold and underlined).

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. **If the manufacturer specification is not available or site capacity differs (e.g., due to site-specific conditions that result in unit uprate or derate), then the capacity reflected in a permit can be used. If a permitted value is not available, capacity defined by the operator can be used.**

Response: No rule change has been made as a result of this comment. The change to Part 98 suggested by the commenter is outside the scope of the specific amendments proposed for public comment in the Federal Register notice of August 11, 2010.

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2008-0508-2383.1

Comment Excerpt Number: 46

Comment: The proposed rule defined “standard conditions” in accordance with the prevalent industry definition of 60°F and 14.7 psia (consistent with all US consensus standards). In comments on the proposed rule, API noted a discrepancy between the stated standard conditions and the “molar volume conversion” factor provided in the equations for calculating emissions from gaseous fuels.

Recent amendments to Subparts X and Y provide two options for “molar volume conversion” factors that can be used by reporters for standard conditions of 60°F and 14.7 psia or 68°F and 14.7 psia. However, the same change has not been made to Subpart C. Currently, Subpart C defines standard conditions of 68°F and 14.7, and the default natural gas heating value in Table

C-1 is based on 60°F and 14.7 psia. The issue is further complicated in the proposed Subpart W, which introduces other, different “standard conditions” for gaseous sources. This inconsistency is extremely confusing and could lead to erroneous emission calculations. In addition, it places an unnecessary burden on reporters.

In addition, the frequently asked questions (FAQ) list on the EPA’s MRR web site was updated in March to state that natural gas billing records that report natural gas usage at standard conditions other than 68°F and 14.7 psia must be corrected to the EPA standard conditions.

API requests that EPA take the following specific actions:

- (1) Adopt a consistent approach for standard conditions throughout the rule, where a short list of “molar volume conversion” factors are provided for different temperature and pressure conditions and instruct reporters to use the appropriate one for their measurement method for quantifying GHG emissions.
- (2) Amend the answer in the FAQ to use industry standard conditions of 60°F and 14.7 psia (1 atmosphere), as specified in the proposed rule, and in accordance with all the consensus industry practice standards listed by EPA in the final MRR.

Response: Please see Section II.G of the preamble for the final rule amendments for the response to this comment. The final rule amendments have revised the definition of standard conditions in §98.6 to include both 60 °F and 68 °F.

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2008-0508-2383.1

Comment Excerpt Number: 19

Comment: API supports the recent amendments to Subparts X and Y which provide two options for “molar volume conversion” factors that can be used by reporters for standard conditions of 60°F and 14.7 psia or 68°F and 14.7 psia. This same option should be included in all subparts of the rule. In particular, Subparts A and C currently defines standard conditions of 68°F and 14.7, while the default natural gas heating value in Table C-1 is based on 60°F and 14.7 psia.

Response: Please see Section II.F of the preamble to the final rule amendments for the response to this comment.

Standardized methods incorporated by reference

Commenter Name: Pamela A. Lacey

Commenter Affiliation: American Gas Association

Document Control Number: EPA-HQ-OAR-2008-0508-2394.1

Comment Excerpt Number: 3

Comment: EPA is proposing to add several specific ASTM and ASME standards to those incorporated by reference in section 98.7 of the MRR. The American Gas Association (AGA) requests that EPA also add the following AGA standards to the list in section 98.7, to facilitate their use:

- (1) AGA Report No. 3 --- Orifice Metering of Natural Gas Part 1: General Equations & Uncertainty Guidelines (1990)
- (2) AGA Report No. 3 --- Orifice Metering of Natural Gas Part 2: Specification and Installation Requirements (2000)
- (3) AGA Report No. 3 --- Orifice Metering of Natural Gas Part 3: Natural Gas Applications (1992)
- (4) AGA Report No. 3 --- Orifice Metering of Natural Gas Part 4: Background, Development Implementation Procedure (1992)
- (5) AGA Report No. 5 --- Natural Gas Energy Measurement (2009)
- (6) AGA Report No. 7 --- Measurement of Natural Gas by Turbine Meter (2006)
- (7) AGA Report No. 8 --- Compressibility Factor of Natural Gas and Related Hydrocarbon Gases (1994)
- (8) AGA Report No. 9 --- Measurement of Gas by Multipath Ultrasonic Meters (2007)
- (9) AGA Report No. 11 --- Measurement of Natural Gas by Coriolis Meter (2003)
- (10) ANSI B109.1 --- Diaphragm-Type Gas Displacement Meters, Capacity Under 500 cft/hr. (2000)
- (11) ANSI B109.2 --- Diaphragm-Type Gas Displacement Meters, Capacity 500 cft/hr. and over (2000)

We have found that when a regulation lists specific standards, it can be difficult to persuade consultants and others that other unlisted standards published by the same consensus standards body may also be used. Therefore, we request that EPA amend the list in 98.7 to include the above listed standards.

Response: The final rule amendments are removing and reserving 40 CFR 98.7(b), which incorporated by reference the AGA reports listed by the commenter in items (1), (2), (6), and (11). The final rule amendments are not adding the other AGA reports or the ANSI standards listed by the commenter. The rationale for removing the AGA reports was explained in the preamble to the proposed amendments for subparts C (75 FR 48761), X (75 FR 48770), and Y (75 FR 48774), published on August 11, 2010. In short, the reference to these AGA methods was removed because the QA/QC sections of these subparts already allowed meters to be calibrated according to “a method published by a consensus-based standards organization.” Maintaining the lists of methods from the AGA was redundant with allowing the use of methods from an organization such as the AGA.

Accordingly, we have not added the other AGA reports and the two ANSI methods. Rather, in many places throughout the document where these reports could have been considered for incorporation by reference, we have finalized the rule to allow the use of standards from consensus-based standards organizations. We then go on to clarify that consensus-based standards organizations include, but are not limited to ASTM, ASME, API, and AGA. Thus, although these methods have not been incorporated by reference in 40 CFR 98.7, as requested by

the commenter, they may still be appropriate to use in accordance with the monitoring and QA/QC requirements in the underlying subparts.

Other Subpart A comments

Commenter Name: Michael Hannan

Commenter Affiliation: Williams Olefins LLC

Document Control Number: EPA-HQ-OAR-2008-0508-2357.1

Comment Excerpt Numbers: 1 - 13

[The commenter suggested several changes to the format of cross-references used in various sections of Subpart A.]

§98.3(c)(6): A written explanation, as required under ~~§98.3~~ paragraph (e) of this section, if you change emission calculation methodologies during the reporting period.

§98.3(g)(5)(ii): The GHG Monitoring Plan may rely on references to existing corporate documents (e.g., standard operating procedures, quality assurance programs under appendix F to ~~40 CFR~~ part 60 of this chapter or appendix B to ~~40 CFR~~ part 75 of this chapter, and other documents) provided that the elements required by paragraph (g)(5)(i) of this section are easily recognizable.

§98.4(a) General. *** If the facility is required under any other part of title 40 of the Code of Federal Regulations to submit to the Administrator any other emission report that is subject to any requirement in ~~40 CFR~~ part 75 of this chapter, the same individual shall be the designated representative responsible for certifying, signing, and submitting the GHG emissions reports and all such other emissions reports under this part.

40 CFR 98.6, Definitions:

COD means the chemical oxygen demand as determined using methods specified pursuant to ~~40 CFR~~ part 136 of this chapter.

Conventional-Summer refers to finished gasoline formulated for use in motor vehicles, the composition and properties of which do not meet the requirements of the reformulated gasoline regulations promulgated by the U.S. Environmental Protection Agency under ~~40 CFR~~ §80.40 of this chapter, but which meet summer RVP standards required under ~~40 CFR~~ §80.27 of this chapter or as specified by the state.***

Conventional-Winter refers to finished gasoline formulated for use in motor vehicles, the composition and properties of which do not meet the requirements of the reformulated gasoline regulations promulgated by the U.S. Environmental Protection Agency under ~~40 CFR~~ §80.40 of this chapter or the summer RVP standards required under ~~40 CFR~~ §80.27 of this chapter or as specified by the state.***

Fluorinated greenhouse gas means sulfur hexafluoride (SF₆), nitrogen trifluoride (NF₃), and any fluorocarbon except for controlled substances as defined at ~~40 CFR~~ part 82 of this chapter, subpart A and substances with vapor pressures of less than 1 mm of Hg absolute at 25 degrees C.***

Landfill means an area of land or an excavation in which wastes are placed for permanent disposal and that is not a land application unit, surface impoundment, injection well, or waste pile as those terms are defined under ~~40 CFR~~ §257.2 of this chapter.

Maximum rated input capacity means the maximum charging rate of a municipal waste combustor unit expressed in tons per day of municipal solid waste combusted, calculated according to the procedures under ~~40 CFR~~ §60.58b(j) of this chapter.

Municipal solid waste landfill or MSW landfill means an entire disposal facility in a contiguous geographical space where household waste is placed in or on land. An MSW landfill may also receive other types of RCRA Subtitle D wastes (~~40 CFR~~ §257.2 of this chapter) such as commercial solid waste, nonhazardous sludge, conditionally exempt small quantity generator waste, and industrial solid waste. ***

Reformulated-Summer refers to finished gasoline formulated for use in motor vehicles, the composition and properties of which meet the requirements of the reformulated gasoline regulations promulgated by the U.S. Environmental Protection Agency under ~~40 CFR~~ §80.40 of this chapter and ~~40 CFR~~ §80.41 of this chapter, and summer RVP standards required under ~~40 CFR~~ §80.27 of this chapter or as specified by the state.

Reformulated-Winter refers to finished gasoline formulated for use in motor vehicles, the composition and properties of which meet the requirements of the reformulated gasoline regulations promulgated by the U.S. Environmental Protection Agency under ~~40 CFR~~ §80.40 of this chapter and ~~40 CFR~~ §80.41 of this chapter, but which do not meet summer RVP standards required under ~~40 CFR~~ §80.27 of this chapter or as specified by the state.***

Table A-3 to Subpart A—Source Category List for §98.2(a)(1)

Source Categories Applicable in 2010 and Future Years

Electricity generation units that report CO₂ mass emissions year round through ~~40 CFR~~ part 75 of this chapter (subpart D)

Response: No rule changes have been made as a result of these comments. The changes to the format of the cross references suggested by the commenter are outside the scope of the specific amendments proposed for public comment in the Federal Register notice of August 11, 2010. Moreover, although we do not necessarily disagree with the changes, we also do not think they are necessary to improve clarity and, as such, have not made changes in the final rule.

Commenter Name: Michael Hannan

Commenter Affiliation: Williams Olefins LLC

Document Control Number: EPA-HQ-OAR-2008-0508-2357.1

Comment Excerpt Number: 14

Comment: §98.33(e)(2) If a CO₂ CEMS (or a surrogate O₂ monitor) and a stack gas flow rate monitor are used to determine the annual CO₂ mass emissions either according to ~~40 CFR~~ part 75 of this chapter, the Tier 4 Calculation Methodology, or the alternative calculation methodology specified in paragraph (a)(5)(iii); and if both fossil fuel and biomass (except for MSW) are combusted in the unit during the reporting year, you may use the following procedure to determine the annual biogenic CO₂ mass emissions

Response: This paragraph is being amended and the format of the cross references in the final rule language follows the format suggested by the commenter.

Commenter Name: Michael Hannan

Commenter Affiliation: Williams Olefins LLC

Document Control Number: EPA-HQ-OAR-2008-0508-2357.1

Comment Excerpt Number: 15, 17, and 18

The commenter suggested several revisions to §98.3(g), Recordkeeping:

Revise §98.3(g)(2)(iii) to include recordkeeping for product analyses.

§98.3(g)(2)(iii) The results of all required analyses for high heat value, carbon content, and other required fuel, ~~or feedstock~~, or product parameters.

Delete §98.3(g)(5)(iv), which is a provision that requires information to be made available to EPA during an audit. It is duplicative of the requirements in the introduction to paragraph (g). If it is not deleted, consider moving it elsewhere. It is a recordkeeping requirement, which does not belong in paragraph (g)(5), which is a description of the GHG Monitoring Plan contents. It could be moved to a new paragraph (g)(8), for instance.

Revise §98.3(g)(6) to include all flow meters since, in addition to fuel flow meters, feedstock, product, and process stream meters may provide data used for GHG emission calculations.

§98.3(g)(6) The results of all required certification and quality assurance tests of continuous monitoring systems, ~~fuel~~-flow meters, and other instrumentation used to provide data for the GHGs reported under this part.

Response: No rule change has been made as a result of this comment. The changes to Part 98 suggested by the commenter are outside the scope of the specific amendments proposed for public comment in the Federal Register notice of August 11, 2010, as we did not propose amendments to these paragraphs in 40 CFR 98.3(g).

Commenter Name: Michael Hannan
Commenter Affiliation: Williams Olefins LLC
Document Control Number: EPA-HQ-OAR-2008-0508-2357.1
Comment Excerpt Number: 22

Comment: There appears to be an error in the citation in the first sentence of §98.4(m)(4), and that “paragraph (m)(2)(iv)(A)” should be replaced with “paragraph (m)(2)(v)(A)”.

Response: No rule change has been made as a result of this comment. The changes to Part 98 suggested by the commenter are outside the scope of the specific amendments proposed for public comment in the Federal Register notice of August 11, 2010, as we did not propose amendments to this paragraph.

Commenter Name: Fiji George
Commenter Affiliation: El Paso Corporation
Document Control Number: EPA-HQ-OAR-2008-0508-2390.1
Comment Excerpt Number: 1

Comment: Requirements for facility address in annual report and abbreviated annual report, in §98.3(c)(1) and §98.3(d)(3)(i): Current language, including changes proposed by the EPA: “Facility name or supplier name (as appropriate), facility or supplier ID number, and physical street address of the facility or supplier, including the city, state, and zip code.”

Suggested language with proposed new language in square brackets: “Facility name or supplier name (as appropriate), facility or supplier ID number, and physical street address of the facility or supplier, including the city, state, and zip code. [If a facility or supplier does not have an address, a description of physical location of facility or supplier must be provided.]”

Incorporation of the suggested changes will provide clarification for facilities and suppliers that do not have a street address.

Response: No rule change has been made as a result of this comment. We are not finalizing amendments to the 2009 final rule to require reporting of facility or supplier ID. Please see Section II.F of the preamble to the final rule amendments for additional information. EPA believes that the language in the final rule is sufficient to identify and locate reporting facilities and suppliers. A Frequently Asked Question (FAQ) will be available on our website shortly to address the few instances where a physical street address may not be available. Please refer to <http://www.epa.gov/climatechange/emissions/ghgrulemaking.html> for more information.

Commenter Name: Jeff Applekamp
Commenter Affiliation: Gas Processors Association (GPA)
Document Control Number: EPA-HQ-OAR-2008-0508-2402.1
Comment Excerpt Number: 3

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2008-0508-2383.1

Comment Excerpt Number: 3

The same comment was submitted by both commenters, with the only difference being the use of “GPA” and “API.”

Comment: 98.3(c)(1) Facility and supplier ID number. EPA proposes to add a requirement for each facility or supplier to report an ID number. The preamble in Section II.F on page 48753 states the exact mechanism for assigning the ID numbers has not yet been determined and EPA will provide necessary guidance later this year. Without knowing the mechanism for assigning the ID numbers, GPA cannot fully review and comment on this proposed revision and anticipates commenting on the guidance when it is issued. GPA requests that EPA provide a separate public comment period when the mechanism and guidance for assigning facility or supplier ID numbers is available.

Response: EPA is not amending the 2009 final rule to require each facility or supplier to report an ID number. Please see section II.F of the preamble for the response to this comment.

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2008-0508-2383.1

Comment Excerpt Number: 44

Comment: Designated Representative Section §98.4(a) requires that each facility and each supplier have “one and only one designated representative, who shall be responsible for certifying, signing, and submitting GHG emissions reports” and other submissions. It is overly burdensome and unnecessary to require each facility and each supplier to authorize only one designated representative. Because the rule broadly defines “facility” in §98.6 to include contiguous or adjacent properties, the rule would unreasonably require that a single person be the designated representative for contiguous or adjacent plants even if they have vastly different responsibilities. This is especially true given the requirement of §98.4(e)(1) that designated representatives certify, among other things, that they “have personally examined, and am familiar with, the statements and information submitted” to EPA. A single designated representative might not have the detailed expertise to evaluate data and emissions from all of the processes of large complex facility. For example, the refinery plant manager who is in the best position to certify an emissions report for a refinery plant is unlikely to have the familiarity or expertise to sign an emissions report for the adjacent chemical plant over which he or she has no authority or control.

Recommendation: We request that EPA delete the requirement that each facility and each supplier have “one and only one designated representative.” We request the language in §98.4 be amended to allow each facility and each supplier to have “one or more designated representatives.” Such an amendment would be consistent with EPA’s approach for Title V

reporting requirements; under that program, facilities in a Title V permit can designate a responsible official for each covered source (40 C.F.R. pts. 70, 71).

Response: No rule change has been made as a result of this comment. The change to Part 98 suggested by the commenter is outside the scope of the specific amendments proposed for public comment in the Federal Register notice of August 11, 2010.

3. SUBPART C – GENERAL STATIONARY FUEL COMBUSTION

Definition of source category

Commenter Name: Sean M. O'Keefe

Commenter Affiliation: Alexander & Baldwin, Inc.

Document Control Number: EPA-HQ-OAR-2008-0508-2380.1

Comment Excerpt Number: 1

Comment: The exemption for emissions from "pilot lights" requires further clarification. EPA has proposed to clarify that GHG emissions from a pilot light need not be included in the emissions totals for a facility by adding a new section 98.30(d) which specifically states, "You are not required to report emissions from pilot lights". A&B supports the proposed clarification, which is justified because a pilot light simply initiates the combustion process in a boiler, turbine, or other fuel combustion device and is not used to produce electricity or steam, or to provide useful energy to an industrial process, or to reduce waste by removing combustible matter. Therefore, for the purposes of Part 98, a pilot is not considered to be a stationary fuel combustion source and pilot gas consumption should not be required to be included in the GHG emissions calculations. However, the proposed section 98.30(d) goes on to state, "A pilot light is a small permanent auxiliary flame that ignites the burner of a combustion device when the control valve opens" (emphasis added). In some boilers, propane or liquefied petroleum gas is used to ignite oil burners when oil firing is initiated in the boiler. The igniter fires gas in the burner for a pre-determined period of time and then extinguishes once combustion of oil in the burner has commenced. The igniter is not a "permanent auxiliary flame" because it does not remain lit once the burner ignition cycle has been completed. The statement that a pilot light is "permanent" would therefore appear to exclude such igniters from the proposed clarifying language, even though they serve the same purpose as a "pilot light" and clearly are also not stationary fuel combustion sources for the purposes of Part 98. Moreover, such igniters would tend to have lower GHG emissions than a pilot light because they fire only intermittently as needed and remain lit for only a short period of time. A&B therefore recommends that the word "permanent" be deleted from the proposed section 98.30(d) in order to clarify that igniters which provide only a temporary flame for burner ignition are also not subject to the GHG reporting requirement.

Response: EPA acknowledges that, in an effort to conserve fuel, pilot lights may not be permanently operated. Accordingly, we have removed the word "permanent" from the definition of pilot light in 40 CFR 98.30(d).

Commenter Name: Sean M. O'Keefe

Commenter Affiliation: Alexander & Baldwin, Inc.

Document Control Number: EPA-HQ-OAR-2008-0508-2380.1

Comment Excerpt Number: 3

Comment: Based on the foregoing discussion and guidance previously provided by EPA, it is A&B's understanding that reporting of GHG emissions from ignition fuels is not required because such fuels simply initiate the combustion process in a boiler, turbine, or other fuel combustion device and are not used to produce electricity or steam, or to provide useful energy to an industrial process, or to reduce waste by removing combustible matter. The proposed clarification of calibration requirements applicable to meters used exclusively for ignition fuels, however, would appear to suggest that reporting of emissions from these fuels is in fact required, since clarification of meter calibration requirements would not be required for fuels for which GHG emissions are not reported. A&B therefore requests that EPA explicitly state in the rule that reporting of GHG emissions from ignition fuels is not required.

Response: EPA agrees with the commenter that pilot lights will effectively be burning an ignition fuel. The language in 40 CFR 98.3(i)(4) was not intended to imply that the fuel consumed in pilot lights is required to be reported. To make this clear, we have removed the word "ignition" from 40 CFR 98.3(i)(4). This modification is not intended to be an expansion of what is considered to be a pilot light.

Commenter Name: Fiji George

Commenter Affiliation: El Paso Corporation

Document Control Number: EPA-HQ-OAR-2008-0508-2390.1

Comment Excerpt Number: 6

Comment: Listing of excluded source categories §98.30(b)(4): Current language: "Flares, unless otherwise required by provisions of another subpart of this part to use methodologies in this subpart." Proposed language: "Flares." The current language may lead reporters to believe that subpart C provides methodologies to calculate emissions from flares.

Response: We are not making the change recommended by the commenter. Although specific methodologies are not provided for flares in Subpart C, other subparts may direct reporters to calculate combustion emissions from destruction devices using the general methodologies provided in Subpart C.

Tier 1 Calculation Methodology

Commenter Name: Michael Hannan
Commenter Affiliation: Williams Olefins LLC
Document Control Number: EPA-HQ-OAR-2008-0508-2357.1
Comment Excerpt Number: 23

Comment: In §98.33(a)(1), EPA added flexibility by adding Equation C-1a to the Tier 1 calculation methodologies. Equation C-1a allows a facility to calculate CO₂ emissions from natural gas combustion when natural gas billing records are used to quantify fuel usage and gas consumption is expressed in units of therms. However, sometimes billing records are expressed in units of energy other than therms (e.g., mmBtu), so the term “therms” should be replaced with the more general “units of energy”. This would require language in the introductory text to specify that the units of energy must be converted to therms for use in Equation C-1a. If this suggested change is accepted, it would necessitate analogous changes to other parts of the rule which are also shown below. Additional clerical corrections are also shown below. Regardless of whether the above suggestion is accepted, a very important omission seemed to be made in that there’s no analogous equation to the new Equation C-1a in §98.33(c) for calculating CH₄ and N₂O emissions. It is proposed below to add a new Equation C-8a for this purpose.

Response: EPA acknowledges that customers may receive natural gas billing information in energy units other than therms. To add more flexibility, we are adding Equation C-1b to calculate emissions when the natural gas billing records are provided in units of mmBtu. We are also adding two new equations to 40 CFR 98.33(c), Equations C-8a and C-8b, for calculating CH₄ and N₂O emissions when the fuel usage information on natural gas billing records is in units of therms or mmBtu. The language in 40 CFR 98.33(b)(1)(v) has also been revised to include mmBtu in addition to therms to explicitly allow the use of the Tier 1 equation when natural gas billing records are received in units of therms.

Commenter Name: Michael Hannan
Commenter Affiliation: Williams Olefins LLC
Document Control Number: EPA-HQ-OAR-2008-0508-2357.1
Comment Excerpt Number: 24

Comment: Changes related to replacing the term “therms” with “units of energy”.

§98.33(a)(1)(i) Use Equation C-1 except when natural gas billing records are used to quantify fuel usage and gas consumption is expressed in units of energy (e.g., mmBtu, therms).***

§98.33(a)(1)(ii) If natural gas consumption is obtained from billing records and fuel usage is expressed in units of energy (e.g., mmBtu, therms), use Equation C-1a. Fuel usage must be converted to therms when using Equation C-1a.

§98.33(b)(1)(v) May be used for natural gas combustion in a unit of any size, in cases where the annual natural gas consumption is obtained from fuel billing records in units of energy (e.g., mmBtu, therms).

Changes related to addition of new Equation C-8a and clerical corrections to promote consistency in language throughout the rule.

§98.33(c)(1)(i) Use Equation C-8 of this section to estimate CH₄ and N₂O emissions for any fuels for which you use the Tier 1 Equation C-1 or Tier 3 Equation C-3, C-4 or C-5 calculation methodologies for CO₂.***

§98.33(c)(1)(ii) Use Equation C-8a of this section to estimate CH₄ and N₂O emissions for natural gas when you use the Tier 1 Equation C-1a calculation methodology for CO₂. Use the same values for natural gas consumption that you use for the Tier 1 calculation.

$CH_4 \text{ or } N_2O = 1 \times 10^{-3} [0.1 * \text{Gas} * \text{EF}]$ (Eq.C-8a)

Where:

CH₄ or N₂O = Annual CH₄ or N₂O emissions from natural gas combustion (metric tons).

Gas = Annual natural gas consumption from billing records (therms).

EF = Fuel-specific default CH₄ or N₂O emission factor for natural gas, from Table C-2 of this subpart (kg CH₄ or N₂O per mmBtu).

0.1 = Conversion factor from therms to mmBtu.

1 x 10⁻³ = Conversion factor from kilograms to metric tons.

§98.33(c)(5) When multiple fuels are combusted during the reporting year, sum the fuel-specific results from Equations C-8, C-8a, C-9a, C-9b, or C-10 of this section (as applicable) to obtain the total annual CH₄ and N₂O emissions, in metric tons.

§98.33(c)(6)(ii)(C) Calculate the annual CH₄ and N₂O emissions from component “i” using Equation C-8, C-8a, C-9a, or C-10 of this section, as applicable.

§98.36(e)((2)(iv)(F) The annual average HHV, when measured HHV data, rather than a default HHV from Table C-1 of this subpart, are used to calculate CH₄ and N₂O emissions for a Tier 3 unit, in accordance with §98.33(c)(1)(i).

Other minor clerical changes to promote consistency in language throughout the rule:

§98.33(c)(2) Use Equation C-9a of this section to estimate CH₄ and N₂O emissions for any fuel for which you use the Tier 2 Equation C-2a calculation methodology of this section to estimate CO₂ emissions.***

§98.33(c)(3) Use Equation C-9b of this section to estimate CH₄ and N₂O emissions for any fuels for which you use the Tier 2 Equation C-2c calculation methodology of this section to calculate the estimate CO₂ emissions.

Response: See the response to comment EPA-HQ-OAR-2008-0508-2357.1 excerpt 23 for an explanation of how we have added more flexibility for using natural gas billing information. Regarding the other changes suggested by the commenter, only two of these have been made, i.e., to §§98.33(c)(5) and (c)(6)(ii)(C), to include references to new Equations C-8a and C-8b. The other recommended changes are outside the scope of this rulemaking and are deemed unnecessary.

Commenter Name: Caitlin Post

Commenter Affiliation: Southern Company

Document Control Number: EPA-HQ-OAR-2008-0508-2377.1

Comment Excerpt Number: 4

Comment: EPA is proposing to amend 40 CFR 98.33(e)(1) to allow the use of Tier 1 to calculate biogenic CO₂ emissions from units that have CO₂ CEMS. Southern Company supports this proposal; however, EPA should clarify that subpart D units that choose to separately report their CO₂ emissions from biomass may also use Tier 1. Southern Company believes it is EPA's intent to allow subpart D units to use Tier 1 to calculate their biogenic CO₂ emissions, but it is not expressly stated.

Response: EPA has finalized requirements for separate reporting of biogenic CO₂ emissions for all subpart D units, as well as other units that follow the alternative methods in 40 CFR part 98.33(a)(5) beginning in the 2011 reporting year. Separate reporting of biogenic CO₂ emissions is optional for the 2010 reporting year.

EPA has concluded that the proposed change to 40 CFR 98.33(e)(1) was sufficiently clear that Subpart D units could also use Tier 1, and we have finalized it, as proposed. In addition, in finalizing these requirements, EPA has provided an additional method in 40 CFR 98.33(e)(6) for calculating emissions from the combustion of biomass fuels. Specifically, EPA has finalized new equation C-15a to calculate biogenic CO₂ emissions. The equation is based on the use of heat input data that may be available from the part 75 electronic data reports, or where this is not possible, from best available information.

Commenter Name: Stephen E. Woock

Commenter Affiliation: Weyerhaeuser Company

Document Control Number: EPA-HQ-OAR-2008-0508-2375.1

Comment Excerpt Number: 6

Comment: §98.33(a)(1)(ii) and §98.33(b)(1)(v): These proposed revisions allow the use of the Tier 1 calculation methodology for natural gas for a unit of any size, if fuel consumption quantities are obtained from billing records with fuel usage expressed in "therms." These revisions provide greater flexibility, without sacrificing accuracy, when calculating GHG emissions from natural gas. First, EPA is correct in using therms as the basic unit. Billing records from natural gas suppliers are typically expressed in therms and Equation C-1a reflects this commonly used unit of measure. Second, allowing the use of Tier 1 for natural gas for any size

unit shows a clear understanding of combustion units that fire natural gas. The combustion of natural gas results in very consistent combustion properties for any combustion unit regardless of size. Therefore, it does not matter what the size of the combustion unit is, Equation C-1a will accurately calculate the CO₂ emissions. Weyerhaeuser supports this revision.

Response: EPA thanks the commenter for the input. We have finalized the proposed requirements. The revision was extended to cases where natural gas billing records are received in mmBtu. Please see the response to comment EPA-HQ-OAR-2008-0508-2357.1 excerpt 23.

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2008-0508-2383.1

Comment Excerpt Number: 22

Comment: API supports the revision of §98.33(a)(3)(iv) – Allows the use of fuel flow meters that measure mass flow rates for gaseous fuels. For liquid fuels, density can be determined using a method published by a consensus standards organization. For gaseous fuels, density can be determined by manufacturer’s instructions, a method published by a consensus standards organization, or an industry practice.

Response: EPA thanks the commenter for the input. The amendments have been finalized, as proposed.

Tier 2 Calculation Methodology

Commenter Name: Rich Raiders

Commenter Affiliation: Arkema Inc.

Document Control Number: EPA-HQ-OAR-2008-0508-2371.1

Comment Excerpt Number: 6

Comment: EPA appropriately provides smaller Subpart C Tier 2 reporters with the flexibility to streamline high heating value (“HHV”) data management. The proposed language at proposed § 98.33(a)(ii)(B) appears to mandate arithmetic averaging of HHV values collected less frequently than monthly or for units smaller than 100 million British Thermal Units (mmBTU) per hour heat capacity. Arkema has already implemented flow-weighted average reporting systems for Tier II reporting facilities. While we appreciate the opportunity to implement either arithmetic or flow-weighted HHV reporting, we request that EPA clarify that reporters may elect to use either averaging method.

Response: By making the modification in 98.33(a), we concluded that we were reducing reporting burden. However, it was not our intent to mandate the use of the less burdensome calculation method. We have revised 40 CFR 98.33(a)(ii)(B) to allow the flexibility of using

either arithmetic or flow-weighted HHV reporting when HHV data are obtained less frequently than monthly, and for smaller units.

Commenter Name: Joel R. Hall

Commenter Affiliation: Mexichem Fluor Inc.

Document Control Number: EPA-HQ-OAR-2008-0508-2365

Comment Excerpt Number: 1

Comment: Mexichem supports the EPA's proposal to allow Tier 2 units that receive monthly (or more frequently) HHV data to use an arithmetic average annual HHV in the emission calculations instead of a fuel-weighted average HHV. We agree that the use of the arithmetic average rather than a fuel-weighted average will not significantly enhance data quality.

Response: EPA thanks the commenter for the input. The final rule provides owners or operators the choice of using an arithmetic average or fuel-weighted average HHV. Please see response to comment EPA-HQ-OAR-2008-0508-2371.1, excerpt 6.

Commenter Name: Bryan Brendle

Commenter Affiliation: Portland Cement Association

Document Control Number: EPA-HQ-OAR-2008-0508-2399.1

Comment Excerpt Number: 2

Comment: PCA members support flexibility being proposed to calculate GHG emissions. For example, EPA proposes to allow the use of billing records for natural gas consumption, when such consumption is expressed in therms. To accommodate this flexibility, EPA proposes to amend the equation C-1a when making those calculations. EPA proposes to add a new paragraph, (b)(1)(v) to 40 CFR 98.33 to reflect this. Section 98.36(e)(2)(1) would also be amended to allow gaseous fuel consumption to be reported in units of therms. PCA members support this measure.

Response: EPA thanks the commenter for the input. Please see the response to comment EPA-HQ-OAR-2008-0508-2357.1 excerpt 23.

Commenter Name: Bryan Brendle

Commenter Affiliation: Portland Cement Association

Document Control Number: EPA-HQ-OAR-2008-0508-2399.1

Comment Excerpt Number: 3

Comment: EPA also proposes to amend 40 CFR 98.33(a)(2)(i) to require calculation of a weighted HHV only for individual Tier 2 units with a maximum rated heat input capacity greater than or equal to 100 mmBtu/hr, and for groups of units that contain at least one unit of that size. For Tier 2 units smaller than 100 mmBtu/hr and for aggregated groups of Tier 2 units under § 98.36(c)(1) in which all units in the group are smaller than 100 mmBtu/hr, the annual arithmetic

average HHV, rather than the annual fuel-weighted average HHV, would be used in Equation C-2a.

Response: EPA thanks the commenter for the input. Note that the final rule provides owners or operators the choice of using an arithmetic average or fuel-weighted average HHV when HHV data are obtained less frequently than monthly, and for smaller units. Please see response to comment EPA-HQ-OAR-2008-0508-2371.1, excerpt 6.

Commenter Name: Jeff Applekamp

Commenter Affiliation: Gas Processors Association (GPA)

Document Control Number: EPA-HQ-OAR-2008-0508-2402.1

Comment Excerpt Number: 6

Comment: 98.33(a)(2)(ii)(B) – Revisions to Tier 2 Calculation Methodology

According to the preamble on page 48765, EPA proposes to “allow” smaller Tier 2 sources (<100 mmBtu/hr) that receive monthly HHV data to use arithmetic annual average HHV instead of fuel-weighted average HHV. The proposed regulatory text change to 98.33(a)(2)(ii)(B) (page 48788) says “If the results of fuel sampling are received less frequently than monthly, or, for a unit with a maximum rated heat input capacity less than 100 mmBtu/hr (or a group of such units) regardless of the HHV sampling frequency, the annual average HHV shall be computed as the arithmetic average HHV for all values for the year (including valid samples and substitute data values under §98.35).”

In the Preamble (pages 48755-8766), EPA notes that “requiring small, low-emitting combustion sources to calculate CO₂ mass emissions using fuel-weighted annual average HHVs instead of arithmetic average values will not significantly enhance data quality.” While GPA agrees with this comment, the amendment does not give companies the option to alternatively calculate HHV based on a weighted average.

Computing HHV on a weighted average is the natural gas industry’s standard, as that is how fuel billing is conducted. For some GPA members, flow rates and heat content are pulled electronically into systems which compute a monthly weighted average HHV. This GHG RP modification would force GPA members to reconfigure software systems, an activity that would likely pose an issue in meeting the March 2011 reporting deadline, or to calculate a separate heat content for GHG RP reporting purposes, thus maintaining two different calculation methods for the same information.

GPA requests that EPA provide the option of calculating HHV based on either a weighted average or an arithmetic average. This could be accomplished by changing the “shall” to “may” in 98.33(a)(2)(ii)(B) to allow reporters that have already set up and implemented systems to calculate flow-weighted average HHV for these sources the option to continue to do so instead of revising their systems.

Response: The final rule provides owners or operators the choice of using an arithmetic average or fuel-weighted average HHV when HHV data are obtained less frequently than monthly, and for smaller units. See the response to comment EPA-HQ-OAR-2008-0508-2371.1 excerpt 6 for an explanation of averaging HHV for Tier 2 sources.

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2008-0508-2383.1

Comment Excerpt Number: 6

Comment: §98.33(a)(2)(i)(B) HHV annual average:

According to the preamble on page 48765, EPA proposes to “allow” smaller Tier 2 sources (<100 MMBtu/hr) that receive monthly HHV data to use arithmetic annual average HHV instead of fuel-weighted average HHV. The proposed regulatory text change to §98.33(a)(2)(i)(B) (page 48788) says “If the results of fuel sampling are received less frequently than monthly, or for a unit with a maximum rated heat input capacity less than 100 MMBtu/hr (or a group of such units) regardless of the HHV sampling frequency, the annual average HHV shall be computed as the arithmetic average HHV for all values for the year (including valid samples and substitute data values under §98.35).”

The “shall” should be revised to “may” to allow reporters that have already set up and implemented systems to calculate flow-weighted average HHV for these sources the option to continue to do so instead of revising their systems.

Response: The final rule provides owners or operators the choice of using an arithmetic average or fuel-weighted average HHV when HHV data are obtained less frequently than monthly, and for smaller units. See the response to comment EPA-HQ-OAR-2008-0508-2371.1 excerpt 6 for an explanation of averaging HHV for Tier 2 sources.

Commenter Name: Fiji George

Commenter Affiliation: El Paso Corporation

Document Control Number: EPA-HQ-OAR-2008-0508-2390.1

Comment Excerpt Number: 7

Comment: Methodology to determine HHV value in § 98.33(a)(ii)(A):

Current language, including changes proposed by the EPA:

“If the results of fuel sampling are received monthly or more frequently, then for each unit with a maximum rated heat input capacity greater than or equal to 100 mmBtu/hr (or for a group of units that includes at least one unit of that size), the annual average HHV shall be calculated

using Equation C-2b of this section. If multiple HHV determinations are made in any month, average the values for the month arithmetically.”

Proposed language with requested changes in square brackets:

“If the results of fuel sampling are received monthly or more frequently, then for each unit with a maximum rated heat input capacity greater than or equal to 100 mmBtu/hr (or for a group of units that includes at least one unit of that size), the annual average HHV shall be calculated using Equation C-2b of this section. If multiple HHV determinations are made in any month, average the values for the month arithmetically. [You may opt to use this method for units of any capacity if the results of fuel sampling are received monthly or more frequently.]”

Using fuel weighted averaging for HHV results in more accurate results than using arithmetic averaging of HHV values. It is assumed that the objective of the change proposed by the EPA was to reduce the reporting burden by allowing less complex averaging methods for smaller units. However, many reporters, including El Paso, have already designed their reporting systems to use fuel weighted averaging for HHV if the HHV values are received on a monthly frequency regardless of the combustion unit capacity. The requirement to use arithmetic averaging will require changes to the already developed systems while decreasing the accuracy of calculated emissions. Therefore, El Paso is requesting the flexibility to use averaging methods as specified in the originally promulgated regulation.

Response: The final rule provides owners or operators the choice of using an arithmetic average or fuel-weighted average HHV when HHV data are obtained less frequently than monthly, and for smaller units. See the response to comment EPA-HQ-OAR-2008-0508-2371.1 excerpt 6 for an explanation of averaging HHV for Tier 2 sources.

Commenter Name: Lauren E. Freeman

Commenter Affiliation: Utility Air Regulatory Group (UARG)

Document Control Number: EPA-HQ-OAR-2008-0508-2388.1

Comment Excerpt Number: 8

Comment: V. Use of Equation C-2b

As promulgated, § 98.33(a)(2)(ii) requires the weighting of HHV results from fuel analysis in proportion to the amount of fuel burned on a monthly basis when using the Tier 2 methodology for any fuel supply for which results are actually obtained at least monthly. In its petition for reconsideration UARG objected to this provision as applied to small units or activities that may trigger the requirement simply because they share a fuel supply with a Part 75 unit that obtains these values at least monthly to satisfy Part 75. Examples of combustion activities that may share fuel supplies with Part 75, Appendix D sources include comfort heating, hot water heating, and other combustion sources that might otherwise qualify for Tier 1 monitoring. Requiring heat input weighting, and estimation of monthly fuel use, for such insignificant activities will provide little benefit to the program. Moreover, because monthly fuel use is being determined solely by

“company records of annual fuel use,” any additional accuracy associated with the HHV weighting process is likely to be lost in the calculation.

In response to UARG’s concerns, EPA proposes to revised § 98.33(a)(2)(ii) to require calculation of weighted HHV only for individual Tier 2 units with a maximum rated heat input capacity greater than or equal to 100 mmBtu/hr and for groups of units that contain at least one unit of that size. 75 Fed. Reg. at 48,755-56. Although UARG continues to question the need for HHV weighting at all for homogenous fuels like natural gas and distillate oil, EPA’s proposed revision is a significant improvement over the current rule and should prevent application of the weighting procedure, and the additional unnecessary recordkeeping and reporting, to insignificant activities. UARG is somewhat concerned, however, that the proposed rule as drafted could be read to prohibit use of the HHV weighting procedure by a unit or group of units with heat input less than 100 mmBtu/hr. Although most small units will want to take advantage of the less onerous procedures, UARG can think of no reason to prohibit HHV weighting if a source chooses to perform the additional work and asks that EPA either reword the provision or confirm in the final rule that the exception is not mandatory.

Response: The final rule provides owners or operators the choice of using an arithmetic average or fuel-weighted average HHV when HHV data are obtained less frequently than monthly, and for smaller units. See the response to comment EPA-HQ-OAR-2008-0508-2371.1 excerpt 6 for an explanation of averaging HHV for Tier 2 sources.

TIER 3 CALCULATION METHODOLOGY

Commenter Name: Michael Hannan

Commenter Affiliation: Williams Olefins LLC

Document Control Number: EPA-HQ-OAR-2008-0508-2357.1

Comment Excerpt Number: 25

Comment: Tier 3 Equations C-4 and C-5 at §98.33(a)(3) define the term “Fuel” and refer to using fuel flow meters calibrated “according to §98.3(i)”. A more appropriate reference would be “according to §98.34(b)” since §98.34(b) includes the requirements of §98.3(i) plus additional requirements for meters used for the Tier 3 calculation methodology.

Response: This comment is outside the scope of the proposed rule. The suggested change is also deemed to be unnecessary. The calibration requirements for flow meters are found in §98.3(i), and all Subpart C sources must comply with the applicable provisions of §98.34.

Commenter Name: Michael Hannan

Commenter Affiliation: Williams Olefins LLC

Document Control Number: EPA-HQ-OAR-2008-0508-2357.1

Comment Excerpt Number: 26

Comment: Revise §98.33(a)(3)(iii) Equation C-5 and §98.253(b)(1)(ii)(B) Equation Y-2 to revise the term “MVC” to be consistent with changes proposed in other parts of the rule. Additionally, revise the reporting requirements at §98.36(e)(2)(iv)(B).

Response: We have revised the nomenclature for Equations C-5 and Y-2 to allow sources to calculate the CO₂ mass emissions using either the MVC value at 60 °F or 68 °F. See the discussion on standard conditions in Section II.G of the Preamble for further information for the changes related to subpart C and section II.N of the preamble to the final rule amendments for the changes related to subpart Y.

Commenter Name: Michael Hannan

Commenter Affiliation: Williams Olefins LLC

Document Control Number: EPA-HQ-OAR-2008-0508-2357.1

Comment Excerpt Number: 28

Comment: In §98.33(a)(3)(v), the reference to ASTM methods should be removed because the reference to specific ASTM methods in paragraph (a)(3)(iv) have been removed and replaced with a much broader array of methods.

Response: We agree with the commenter. In the final rule, since the reference to a specific ASTM method for measuring density has been removed from §98.33(a)(3)(iv), we have also removed from §98.33(a)(3)(v) the cross-reference to that ASTM method.

Commenter Name: Keith W. Holman

Commenter Affiliation: National Lime Association (NLA)

Document Control Number: EPA-HQ-OAR-2008-0508-2361.1

Comment Excerpt Number: 1

Comment: EPA published a proposed rule on August 11, 2011 clarifying specific provisions of the GHGRR and making technical and editorial corrections. While the proposed rule corrects many of the errors in the original GHGRR rule, we note that the proposed rule does not address necessary changes to Equation C-5, which sets forth the Tier 3 method for calculating emissions from the combustion of gaseous fuel. In the original GHGRR rule, the carbon content definition referred to liquid fuels. While the proposed rule acknowledges this error and notes that the definitions of carbon content and molecular weight will be revised in Equation C-5, the definition of carbon content needs to include a reference to gaseous fuel and include the correct units (k C/kg of fuel). These changes, together with an accompanying discussion, were included as revisions on pages 137 and 138 of the redline version of the proposed revisions that EPA posted on its website. http://www.epa.gov/climatechange/emissions/downloads10/MRR-Revisions_Redline.pdf. NLA will look for these changes to be included in the final GHGRR revisions rule.

Response: In our proposed amendments, the definition of Carbon Content (CC) in Equation C-5 was amended to correct the units of measure. This proposed amendment was published without error in the August 11, 2010 Federal Register notice, and we have finalized it, without modification. As such, no further action is needed on this issue.

Commenter Name: Stephen E. Woock

Commenter Affiliation: Weyerhaeuser Company

Document Control Number: EPA-HQ-OAR-2008-0508-2375.1

Comment Excerpt Number: 7

Comment: §98.33(a)(3)(iv): This proposed revision allows the density of the fuel to be determined by industry standards or other established references, rather than requiring laboratory testing of the fuels. For gaseous fuels, the density of the fuel may be determined either by a calibrated density meter, a published consensus standard or an industry standard practice. For liquid fuels, a published consensus standard, an industry standard practice or default density value provided in §98.33(a)(3)(v) can be used. In general, the densities of liquid and gaseous fuels do not vary significantly, therefore the use of published densities, industry standard values, or EPA provided values is appropriate. The key is to consistently use the same referenced value, which most facilities will tend to do once they decide on which reference best represents their fuel type. This revision provides greater flexibility for the facilities to select the proper conversion methodology, as well as eliminating the unnecessary fuel testing costs. Weyerhaeuser supports this revision.

Response: EPA thanks the commenter for the input and we have finalized the amendments, as proposed.

Commenter Name: Robert Rouse

Commenter Affiliation: The Dow Chemical Company

Document Control Number: EPA-HQ-OAR-2008-0508-2366.1

Comment Excerpt Number: 4

Comment: EPA Should Make Further Changes to the Rule Due to the Addition of "Fuel Gas" to Table C-1.

The proposed addition of "Fuel Gas" to Table C-1 of the Reporting Rule has additional impacts on the implementation of this rule that EPA should account for as detailed below:

#1 - Fuels used in combustion units with a heat input > 250 MMBtu/hr are required to use Tier 3 if the fuel combusted is listed in Table C-1 unless the fuel is natural gas or distillate. At a minimum, if these fuels provide less than 10% of the annual heat input, they should be excluded from the reporting requirements just like fuels that do not have an emission factor provided in Table C-1. Otherwise, even the presence of a small amount of fuel gas in a gas mixture will

trigger the Tier 3 requirements. The following regulatory text should be added to 98.33(b)(3)(B)(iii) regarding Tier 3 requirements:

Shall be used for a fuel listed (except for natural gas and distillate fuel oil) in Table C-1 and for a fuel not listed in Table C-1 of this subpart if the fuel is combusted in a unit with a maximum rated heat input capacity greater than 250 mmBtu/hr (or, pursuant to 98.36(c)(3)' in a group of units served by a common supply pipe, having at least one unit with a maximum rated heat input capacity greater than 250 mmBtu/hr). provided that both of the following conditions apply:

(A) The use of Tier 4 is not required.

(B) The fuel provides 10 percent or more of the annual heat input to the unit or, if 98.36Cc) applies, to a group of units served by common pipe.

Response: The term “still gas” was changed to “fuel gas” to be more consistent with the terminology commonly used by industry. We did not intend to introduce Tier 3 requirements for units that would not have otherwise been subject to Tier 3 prior to the proposed change. We have addressed this concern in the final rule by modifying the definition of “fuel gas” to include only fuels generated at petroleum refineries or petrochemical processes subject to subpart X of the rule. For additional information regarding the final amendments related to fuel gas, please refer to section II.G of the preamble to the final rule amendments.

We do not agree with the commenter that for traditional fuels there should be a 10% cutoff point below which no GHG emissions reporting is required. The 10% rule in Tier 3 is only for unconventional fuels that are not listed in Table C-1. Moreover, this general suggestion is outside the scope of the August 11, 2010 proposal.

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2008-0508-2383.1

Comment Excerpt Number: 39

Comment: Section §98.34(b)(3)(ii)(E) provides as follows: “For gaseous fuels other than natural gas and biogas (e.g., refinery gas), daily sampling and analysis to determine the carbon content and molecular weight of the fuel is required if the necessary equipment is in place to make these measurements. Otherwise, weekly sampling and analysis shall be performed.”

The Tier 3 CO₂ emissions calculation methodology in Section §98.33(a)(3)(iii) for gaseous fuels defines carbon content and molecular weight of the fuel in terms of annual average and refers to section §98.33(a)(2)(ii) for the procedure on how to determine the annual average.

Section §98.33(a)(2)(ii) states when the frequency of the sample is monthly or more frequently, the annual average shall be calculated using Equation C-2b which provides a weighted annual average based on fuel quantity. This procedure for calculating annual average when an on-line gas chromatograph (GC) is used to determine carbon content may be burdensome depending

upon whether or not the GC is connected to a data management system and how the data management system is configured. A typical on-line GC will analyze a sample about every 15 minutes. Thus, the carbon content and molecular weight annual weighted average consists of 35,040 calculations per year per fuel gas stream.

The rule references §98.33(a) methodologies for carbon content and molecular weight, which still requires the use of all values for the year. We request that EPA allow refineries to use calculated weekly average carbon content and molecular weight when an on-line GC is used to analyze fuel gas content.

Response: Equation C-2b uses a maximum of 12 monthly average HHVs and 12 monthly fuel usage values to determine a weighted average annual HHV. In the final rule, we have clarified the term “HHV” in the nomenclature of Equation C-2b, to indicate that each monthly average HHV in the equation may be a composite of many samples taken at a particular frequency. This same approach applies when the equation is used for weighted average carbon content (CC) or molecular weight (MW) determinations. The rule does not specify how the monthly average of HHV, CC, or MW is to be obtained. The commenter has suggested that the use of weekly averages should be allowed. We agree. A monthly average value determined by averaging four weekly averages (where each weekly average is calculated by the data management system using the individual 15 minute readings for that week) satisfies the rule requirement to use all available data in the monthly average, and is acceptable for any of these parameters.

Tier 4 Calculation Methodology

Commenter Name: Kerry Kelly

Commenter Affiliation: Waste Management (WM)

Document Control Number: EPA-HQ-OAR-2008-0508-2360.1

Comment Excerpt Number: 5

Comment: WM supports EPA’s proposal to clarify that reporters required to provide gas stack moisture content using Part 75 methodologies may use site-specific moisture values where none are specified in part 75. As EPA notes in the preamble, many such site-specific values have been approved for use by the Agency in the Acid Rain program.

Response: EPA thanks the commenter for the input. We have finalized the amendment allowing site-specific moisture values to be used where none are specified in part 75.

Commenter Name: John H. Skinner

Commenter Affiliation: Solid Waste Association of North America (SWANA)

Document Control Number: EPA-HQ-OAR-2008-0508-2397.1

Comment Excerpt Number: 3

Comment: The Solid Waste Association of North America (SWANA) agrees with EPA's proposed clarification regarding the use of site-specific moisture values when none are specified in part 75. This approach is similar to that of EPA's Acid Rain Program.

Response: EPA thanks the commenter for the input. We have finalized the amendment allowing site-specific moisture values to be used where none are specified in part 75. See section II.G of the preamble to the final rule amendments for further information.

Commenter Name: Lorraine Krupa Gershman

Commenter Affiliation: American Chemistry Council

Document Control Number: EPA-HQ-OAR-2008-0508-2368.1

Comment Excerpt Number: 4

Comment: Section 98.33(a)(4)(iii) proposes changes to the requirements for determining the specific default moisture values using measurements with EPA Method 4. For each site-specific default moisture percentage, at least nine Method 4 runs are required, and moisture data from the relative accuracy test audit (RATA) of a CEMS may be used for this purpose. However, §98.34(c)(3) provides flexibility for the owner/operator to follow the applicable procedures in appendix B to 40 CFR part 75, appendix F to 40 CFR 60, or an applicable state continuous monitoring program. This proposed rule should be consistent throughout, and therefore allow owner/operators the ability to utilize less than nine Method 4 runs if a state continuous monitoring program allows for such alternatives. The moisture content of a larger flue gas stream is not expected to vary significantly over the course of an emission test or RATA. ACC recommends that EPA should modify this requirement, and require a minimum of three Method 4 runs in order to determine the site-specific moisture percentage.

Response: EPA agrees with the commenter. The commenter correctly notes that situations exist where fewer than nine Method 4 runs need to be performed during a RATA. Various regulatory programs allow for a single moisture determination to represent multiple RATA runs. We have amended 40 CFR 98.33(a)(4)(iii) to allow for the default moisture content value to be based on the number of moisture runs required by the applicable RATA regulation. See section II.G of the preamble to the final rule amendments for further information.

Commenter Name: Ted Michaels

Commenter Affiliation: Energy Recovery Council (ERC)

Document Control Number: EPA-HQ-OAR-2008-0508-2393.1

Comment Excerpt Number: 4

Comment: The Energy Recovery Council (ERC) supports EPA's proposal to clarify that reporters required to provide gas stack moisture content using Part 75 methodologies may use site-specific moisture values where none are specified in part 75. As EPA notes in the preamble,

many such site-specific values have been approved for use by the Agency in the Acid Rain program.

Response: EPA thanks the commenter for the input. We have finalized the amendment allowing site-specific moisture values to be used where none are specified in part 75.

Commenter Name: Robert Rouse

Commenter Affiliation: The Dow Chemical Company

Document Control Number: EPA-HQ-OAR-2008-0508-2366.1

Comment Excerpt Number: 2

Comment: EPA Should Modify the Requirements to Measure a Site-Specific Default Moisture Percentage for Tier 4 Emission Calculations.

Section 98.33(a)(4)(iii) proposes changes to the requirements for determining the specific default moisture values using measurements with EPA Method 4. For each site-specific default moisture percentage at least nine Method 4 runs are required and moisture data from the relative accuracy test audit (RATA) of a CEMS may be used for this purpose.

Section 98.34(c)(3) provides flexibility for the owner/operator to follow the applicable procedures in either appendix B to 40 CFR part 75, appendix F to 40 CFR 60, or an applicable State continuous monitoring program. Thus, this proposed rule change should also provide flexibility for the owner/operator to use less than nine Method 4 runs if a State continuous monitoring program allows for such alternatives. The moisture content of a larger flue gas stream is not expected to vary significantly over the course of an emission test or RATA. Therefore, EPA should modify this requirement to require a minimum of three Method 4 runs (instead of nine) in order to determine the site-specific moisture percentage. Execution of nine Method 4 runs is overly burdensome when the results are expected to be similar between test runs.

Response: See the response to comment EPA-HQ-OAR-2008-0508-2368.1 excerpt 4 for an explanation of the number of Method 4 runs required.

Commenter Name: Bryan Brendle

Commenter Affiliation: Portland Cement Association

Document Control Number: EPA-HQ-OAR-2008-0508-2399.1

Comment Excerpt Number: 6

Comment: EPA also proposes to amend 40 CFR 98.33(a)(4)(iii) to allow the use of site-specific moisture constants under the Tier 4 methodology. The site-specific moisture default value(s) would have to represent the fuel(s) or fuel blends that are combusted in the unit during normal, stable operation, and would have to account for any distinct difference(s) in stack gas moisture content associated with different process operating conditions. For each site-specific default

moisture percentage, at least nine runs would be required using EPA Method 4—Determination of Moisture Content in Stack Gases (40 CFR Part 60, Appendix A–3). Moisture data from the relative accuracy test audit (RATA) of a CEMS could be used for this purpose. Each site-specific default moisture value would be calculated by taking the arithmetic average of the Method 4 runs. Each site-specific moisture default value would be updated at least annually, and whenever the current value is believed to be non-representative, due to changes in unit or process operation. The updated moisture value would be used in the subsequent CO₂ emissions calculations. Many cement manufacturers support this additional measure, although timing constraints have forced some companies to move forward with installation of moisture analyzers, making this proposal in some respects too late to allow flexibility with respect to compliance.

Response: EPA thanks the commenter for the input. We have finalized the amendment allowing site-specific moisture values to be used where none are specified in part 75. See section II.G of the preamble to the final rule amendments for further information.

Companies that have moved forward with the installation of moisture sensors are under no obligation to continue using them, and may, at any convenient time, determine and use site-specific moisture default values instead. All such changes in the CO₂ emissions calculation methodology must be documented in the monitoring plan.

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2008-0508-2383.1

Comment Excerpt Number: 7

Comment: Per the requirements of §98.33(a)(4)(iii): If you measure CO₂ emissions for Tier 4 methodology on a dry basis, then you must apply a moisture correction to your mass flow calculation using equation C-7. The same paragraph also contains changes which state:

“you may determine an appropriate site specific default moisture value (or values), using measurements made with EPA Method 4—Determination Of Moisture Content In Stack Gases, in appendix A–3 to part 60 of this chapter. If this option is selected, the site specific moisture default value(s) must represent the fuel(s) or fuel blends that are combusted in the unit during normal, stable operation, and must account for any distinct difference(s) in the stack gas moisture content associated with different process operating conditions. For each site specific default moisture percentage, at least nine Method 4 runs are required. Moisture data from the relative accuracy test audit (RATA) of a CEMS may be used for this purpose. Calculate each site-specific default moisture value by taking the arithmetic average of the Method 4 runs.”

At the typical stack temperatures that most FCC wet gas scrubbers operate, a small change in temperature can mean a big change in the moisture content. The change in moisture content is approximately 0.5% moisture per degree Fahrenheit in the 140 degree to 160 degree range. Using the average of nine Method 4 runs as EPA proposes, covering different process operating

conditions, could result in significant error in the moisture content of the stack when the stack temperature changes by even a few degrees from the "average".

This same process would not apply to "non-saturated" stacks like heaters as the moisture content is not likely to be at the saturation value for the stack temperature.

API requests that EPA allow an option to use a calculated moisture value based on the saturation value for moisture at the actual temperature of the stack. This would be done using a standard equation for determining the moisture content, such as:

$$\frac{0.1450377 \times 6.112 \times 10^{\frac{7.5 \times T_c}{T_c + 237.7}}}{\text{AtmP} \times 100}$$

Where:

Tc is the temperature in degrees Celsius

Atm P is actual atmospheric pressure for the site

0.1450377 is a conversion factor from millibars to PSIA.

This follows the logic set forth in Reference Method 4, which states that if the measured moisture content of the stack using isokinetic sampling, is greater than the calculated saturation value for moisture at the actual stack temperature, then you should use the calculated saturation value as the moisture value for the test.

Response: The commenter is requesting a method to calculate moisture content for a saturated stack based on temperature measurements. EPA has determined that the rule is already sufficiently flexible to satisfy the commenter's request. In 40 CFR 98.33(a)(3)(iii) the reporter is given the option of either using a continuous monitoring method in 40 CFR 75.11(b)(2) or to apply an appropriate default moisture percentage. Included in 40 CFR 75.11(b)(2) is the option to use a temperature sensor and a moisture look-up table (e.g., a psychrometric chart). This option is only allowed for a gas stream that is demonstrably saturated (e.g., following a wet scrubber). Since this option already exists and is allowed by 40 CFR 98.33(a)(3)(iii), EPA is not making any additional changes. Note that the standard equation proposed by the commenter may be used, provided that it gives results equivalent to those obtained from a psychrometric chart.

Commenter Name: Bryan Brendle

Commenter Affiliation: Portland Cement Association

Document Control Number: EPA-HQ-OAR-2008-0508-2399.1

Comment Excerpt Number: 11

Comment: CO₂ Emissions from Coal Mill Stacks

In addition to having concerns about methods for calculating biogenic emissions and the scope of regulatory definitions, at least one PCA member addresses EPA's proposal for section §98.33

(a)(4)(viii) that may apply to the separate coal mill stack in cement plants. In this section EPA state that:

“If a portion of the flue gases generated by a unit subject to Tier 4 (e.g., a slip stream) is continuously diverted from the main flue gas exhaust system for the purpose of heat recovery or some other similar process, and then exhausts through a stack that is not equipped with the continuous emission monitors to measure CO₂ mass emissions, provided that the CO₂ concentration in the diverted stream is not altered in any way (e.g., by chemical reaction or dilution) before the diverted stream exits to the atmosphere, an estimate of the hourly average volumetric flow rate (scfh) of the diverted gas stream shall be made at the point where it exits the main exhaust system, by using the best available information (e.g., 143 correlations of operating parameters versus flow measurements made with EPA Method 2 in appendix A-2 to part 60 of this chapter, engineering analysis, or other methods). Each hourly average volumetric flow rate (scfh) measured at the main flue gas stack shall then be added to the corresponding estimate of the hourly average flow rate of the diverted gas stream, to determine the total hourly average stack gas volumetric flow rate "Q", for use in Equation C-6 of this section. The method use to estimate the hourly flow rate of the diverted portion of the flue gas exhaust stream shall be documented in the Monitoring Plan required under §98.3(g)(5). “

This revision addresses comments submitted by a PCA member pertaining to the separate coal mill stack that contains a slip stream of kiln gas. EPA’s intention is to allow using the best information to estimate the CO₂ from the coal mill stack without installing an additional CO₂ CEM system. However, the improper pre-conditions and non-practical method in the section will not make this purpose realized.

A. The rule requires that “the diverted stream is not altered in any way (e.g., by chemical reaction or dilution)”. It is reasonable to require there is no more chemical reaction so that no more CO₂ will be generated. However, it is impossible that the diverted stream has no any dilution for two reasons:

1 There are ductworks and fan that introduces this stream to a separate stack. The system must have additional false air and more or less dilute the gas stream;

2 For the “heat recovery” purpose, additional equipment with dust collector is typically installed in the diverted stream, such as the coal mill and dust collect in the cement plants. These equipment may bring more false air and dilute the stream.

Member recommendation: simply remove the words “or dilution” in the bracket. Any such diverted stream must have some false air in the system.

B. The rule requires estimating the actual flow rate in the diverted stream and then to add it to the main stream. Actually, it does not work because both streams have different false air due to different duct works, fans, heat recovery equipment and dust collectors, etc. The CO₂ concentrations are diluted in a different ratio and could be significantly different in the two stacks. A simple addition of flow rate may cause some significant errors. Even in the gas flow of the diverted gas stream at the point where it exits the main exhaust system, the CO₂ concentration will be different with the main stack since the false air in the main stream.

This recommendation to estimate the CO₂ emission in the diverted stream has been sent to EPA before, and provided as following:

* The plants will conduct an initial stack test on the coal mill stack and follow-up testing as needed. The CO₂ emission rate (tons per hour) will be measured in the coal mill stack. During the coal mill stack test, the coal mill system will operate under normal conditions at a minimum of 90% of its rated capacity.

* The CO₂ emission from the coal mill stack will be calculated using the measured average tons/hr CO₂ emission times the total coal mill operation hours in a year. The coal mill operation hours will be obtained from the company record.

* The sum of the CO₂ emissions recorded by the kiln stack CEM and the calculated emissions from the coal mill stack will be reported as total kiln stack CO₂ emissions.

If EPA prefers to use their approach: adding the hourly average flow rate of the diverted gas stream to the main stream “to determine the total hourly average stack gas volumetric flow rate "Q", for use in Equation C-6”, then since the CO₂ concentration will be different, we suggest estimating the “equivalent” flow rate in the diverted stream. The ratio of the equivalent flow rate in the diverted stream and the actual flow rate in the main stack should be the same ratio of the CO₂ ton/hour in the diverted stream and in the main stack determined during the stack tests. Only after the modification of the precondition and the estimation approach, this section can then be used in the diverted stream such as the coal mill stack in cement plants.

Response: In the final rule, we have incorporated the stack testing approach suggested by the commenter, with a few modifications to account for any significant variability in the volumetric flow rate of the diverted gas stream. Please see EPA’s discussion on determining emissions from an exhaust stream diverted from a CEMS monitored stack in Section II.G of the preamble to the final rule amendments, for further information.

Tier 1 Applicability

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2008-0508-2383.1

Comment Excerpt Number: 23

Comment: API supports the revision of §98.33(b)(1)(v) – Allows the use of Tier 1 methods for natural gas combustion in a unit of any size in cases where the annual natural gas consumption is obtained from fuel billing records in units of therms.

Response: EPA thanks the commenter for the input. We have finalized this provision to allow the use of Tier 1 methods for natural gas combustion in a unit of any size in cases where the

annual natural gas consumption is obtained from fuel billing records in units of therms. Please see section II.G of the preamble to the final rule amendments, for further information.

Tier 2 Applicability

Commenter Name: Mike Stroben

Commenter Affiliation: Duke Energy

Document Control Number: EPA-HQ-OAR-2008-0508-2354.1

Comment Excerpt Number: 2

Comment: EPA's proposal to change the minimum sampling frequency for Tier 2 will have the unintended effect of forcing many Tier 1 fuel/units into Tier 2.

The final Mandatory Greenhouse Gas Reporting Rule (74 FR 56260-56519 on October 30, 2009) made it clear that if a fuel consumed by a combustion source of less than 250 mmBtu/hr capacity was not sampled and analyzed at the minimum frequency specified in §98.34(a) of that rule, then fuel for that source could be considered Tier 1 in Subpart C (see §98.33(b)(1)(iv)) (74 FR 56400). For example, the current rule requires a Tier 2 unit consuming fuel oil is to analyze a sample from every lot or delivery. If this is not occurring and the unit meets other Tier 1 criteria, then the unit is Tier 1 for fuel oil, and fuel oil sampling and analysis is not required. With this proposed rule (75 FR 48744 on August 11, 2010), EPA would change those sampling frequency minimums, forcing many Tier 1 units into Tier 2. While Duke Energy acknowledges that EPA's motive for decreasing the required frequency of sampling by some Tier 2 sources is laudable, this action will force a lot of small sources into unnecessary sampling regimes.

EPA can remedy this situation most easily by slightly altering the Tier 1 requirements of §98.33(b)(1). Duke Energy requests that EPA delete the requirement of §98.33(b)(1)(iv) and instead provide any unit that meets the requirements of §98.33(b)(1)(i-i ii ,v) the option to use Tier 1 criteria.

§98.33(b)(1)(iv) [The Tier 1 calculation methodology] May not be used if you routinely perform fuel sampling and analysis for the fuel high heat value (HHV) or routinely receive the results of HHV sampling and analysis from the fuel supplier at the minimum frequency specified in §98.34(a), or at a greater frequency. In such cases, Tier 2 shall be used.

This change would allow any small (<250 mmBtu/hr) units consuming a fuel listed in Table C-1 to use the default HHV in Table C-1 regardless of sampling frequency and analysis methods that might also be occurring at the facility. Larger units and units consuming fuels not listed in Table C-1 would continue to use Tier 2 and Tier 3 methods.

This relief would clear up a lot of confusion surrounding Tier 1 vs Tier 2 applicability, including the shifting definition of "routinely". Also, as the fuels listed in Table C-1 are all fungible fuels of consistent quality, allowing small sources to use the default factors in Table C-1 will not affect the quality of this program.

Response: The intent of Tier 2 is to require units to report fuel analysis only if they are already performing sampling or receive the results of fuel sampling from the supplier at the minimum frequency specified in §98.34(a)(2). For fuel oil, Tier 2 is required if, for each collective fuel lot, at least one sample is taken and analyzed as part of the facility's normal operating procedures. Since a fuel lot can be aggregated to the monthly level, Tier 2 will typically be required if a representative sample is analyzed at least once a month. For units smaller than 250 mmBtu that are subject to Tier 2 because they meet the minimum sampling frequency, no additional sampling requirements are being imposed. Note that at the request of other commenters, additional sampling options for fuel oil (e.g., sampling after each addition of oil to the tank, daily manual sampling, etc) have been added to the final rule. Units that use these sampling methods as part of their normal operation and might otherwise have qualified for Tier 1 will also be required to use Tier 2.

We recognize that there may be some facilities that rightfully assumed they would use Tier 1 for the 2010 reporting year, based on the 2009 final rule, and retained the corresponding records. These same facilities might not have the information available to follow Tier 2 based on the revised definition of fuel lot. Where this is the case, and the appropriate records have not been retained by the facility for the 2010 reporting year, we interpret this to mean that the facility did not have the data available at the required frequency in 2010, and therefore would not be required to use Tier 2 for the 2010 reporting year.

Note that although the amendments may require more sources to use Tier 2 than originally anticipated, no additional fuel sampling requirements are being imposed. The use of Tier 2 is triggered for these units only because they obtain or receive HHV data at a certain frequency, as part of their normal operation.

Tier 3 Applicability

Commenter Name: Lorraine Krupa Gershman

Commenter Affiliation: American Chemistry Council

Document Control Number: EPA-HQ-OAR-2008-0508-2368.1

Comment Excerpt Number: 6

Comment: Fuels used in combustion units with a heat input greater than 250 MMBtu/hr are required to use the Tier 3 calculation method if the fuel combusted is listed in Table C-1, unless the fuel is natural gas or distillate fuel oil. However, ACC believes that if these fuels provide less than 10% of the annual heat input, these fuels should be excluded from the reporting requirements just like fuels that do not have any emission factor provided in Table C-1. Otherwise, even the presence of a small amount of fuel gas in a gas mixture will trigger the Tier 3 methodology, which requires calibrated flow meters to determine fuel quantity and periodic sampling and analysis to determine fuel composition. Based on the October 2009 final rule, petrochemical plants that burn "fuel gas" in combustion units with a heat input less than 250

MMBtu/hr or with a heat input greater than 250 MMBtu/hr where “fuel gas” provides less than 10% of the annual heat input, were not required to calculate GHG emissions because fuel gas was not listed in Table C-1.

Response: Please see response to comment EPA-HQ-OAR-2008-0508-2366.1, Excerpt 4 for the response to this comment.

Commenter Name: Kimberly A. Hibbard

Commenter Affiliation: S.D. Warren Company - Somerset Operations

Document Control Number: EPA-HQ-OAR-2008-0508-2404

Comment Excerpt Number: 2

Comment: S .D. Warren urges EPA to revise its proposed changes to provide that fuels listed in Table C-1 which provide less than 10% of the annual heat input to a boiler with a maximum rated heat input capacity >250 MMBtu/hr be allowed to use Tier 1 for calculating GHG emissions for such fuels (i.e. use of company records and default emission factors). .

Another potential issue with the use of Tier 3 for waste oil is found in 98.43(b)(1)(vi) . Would the addition of waste oil into the No.6 fuel oil tank be considered as a mixture of fuels transported by a common pipe requiring measurement of fuels with a certified flow meter prior to mixing? Would the mill have to install a new storage tank and flow meter system for waste oil in order to meter the fuels separately prior to mixing as specified by 98.43(b)(1)(vi)? This requirement also seems excessive and impracticable for such a small fuel stream.

Response: The request to use Tier 1 for Table C-1 fuels that provide less than 10% of the annual heat input to large (greater than 250 mmBtu/hr) combustion units is outside the scope of this rulemaking. EPA did not propose any changes to the requirements of the current rule regarding the allowable CO₂ emissions calculation methodologies for Table C-1 fuels. See also the response to comment EPA-HQ-OAR-2008-0508-2366.1, excerpt 4.

Regarding the addition of waste oil to a No. 6 oil storage tank, the method of quantifying the CO₂ emissions from the mixed oil depends on the size of the unit (or units) combusting the fuel. The final rule provides emission factors for both “used oil” and No. 6 oil. So if the unit’s maximum rated heat input capacity is 250 mmBtu/hr or less and the fuels are not precisely measured before mixing, you could consider the mixture (blend) to be the “fuel type”, use the best available information to estimate the relative proportions of the two fuels in the mixture, and then apply the Tier 2 methodology in §98.34(a)(3)(ii) for a blend of Table C-1 fuels. If the unit is greater than 250 mmBtu/hr, the use of Tier 3 would be triggered. However, you could consider the blend to be the fuel type and apply the Tier 3 methodology in §98.34(b)(3)(v) for blended fuels. Note that Tier 3 allows the use of tank drop measurements as an alternative to installing calibrated fuel flow meters (see the definition of “Fuel” in the nomenclature of Equation C-4). The minimum required sampling frequency for a blend of liquid fuels is once per calendar quarter, under both Tier 2 and Tier 3 (see §§98.34(a)(2)(v) and (b)(3)(ii)(F)).

Commenter Name: Kimberly A. Hibbard
Commenter Affiliation: S.D. Warren Company - Somerset Operations
Document Control Number: EPA-HQ-OAR-2008-0508-2404
Comment Excerpt Number: 3

Comment: The Somerset Mill has a similar issue with the firing of No.2 Fuel oil in the No. 2. Power Boiler as an igniter fuel. On average No.2 fuel oil provides less than 10/6 [sic] of the annual heat input to the No.2 Power Boiler. Because No.2 Fuel Oil is listed in Table C-1 and is burned in a boiler with a maximum rated heat input capacity >250 MMBtu/hr, a fuel analysis of the higher heating value (HHV) for Tier 2 (98.34(a)(2)(ii)) or a fuel analysis of the carbon content for Tier 3 (98.34(b)(3)) of every lot or shipment is required.

When the Somerset Mill requested the supplier of No.2 Fuel Oil to provide copies of the HHV for each shipment, the mill was informed that there were no suppliers or distributors currently testing cargos of No .2 oil throughout New England and that the comingling of No.2 oil prior to delivery to the ultimate user is a common practice. The testing of each No.2 fuel oil delivery to the mill, which is a relatively small volume compared to No.6 oil cargo testing, seems excessive for a fuel that provides less than 1 % of the annual heat output to the No.2 Power Boiler. Similar to the waste oil issue, the Somerset Mill recommends the use of Tier 1 to calculate greenhouse gas emissions for small quantities of igniter fuel.

Response: The changes to Part 98 suggested by the commenter are outside the scope of the specific amendments proposed for public comment in the Federal Register notice of August 11, 2010. However, note that if the No. 2 oil is combusted in a manner consistent with the definition of a pilot light in §98.6, then the fuel is exempted from GHG emissions reporting under §98.30(d).

Commenter Name: Karin Ritter
Commenter Affiliation: American Petroleum Institute (API)
Document Control Number: EPA-HQ-OAR-2008-0508-2383.1
Comment Excerpt Number: 24

Comment: API supports the revision of §98.34(b) and the use of the terminology – For Tier 3 oil and gas flow meters, you may use an appropriate flow meter calibration method published by a consensus standards organization.

Response: EPA thanks the commenter for the input. We have finalized this provision, as proposed.

Tier 4 Applicability

Commenter Name: Kerry Kelly
Commenter Affiliation: Waste Management (WM)

Document Control Number: EPA-HQ-OAR-2008-0508-2360.1

Comment Excerpt Number: 6

Comment: WM supports the proposed applicability threshold for requiring use of Tier 4 methodologies. The proposed 600 tons per day threshold will relieve smaller, primarily municipally-owned MSW combustor units from having to retrofit and install expensive new monitoring equipment that is inconsistent with the monitoring equipment required by the New Source Performance Standards for those units. At the same time, the 600 ton per day applicability threshold for MSW combustors is far more stringent than the threshold applied to fossil fuel-fired combustors that emit significantly larger amounts of greenhouse gases.

Response: EPA thanks the commenter for the input. However, please note that the 600 tons per day (tpd) threshold is not more stringent than the threshold for fossil fuel combustors. On a heat input basis, 600 tpd of MSW compares quite well to the 250 mmBtu/hr threshold for fossil fuel-fired units. In fact, the main reason for raising the MSW threshold to 600 tpd was to put MSW and fossil fuel combustors on a more equal footing (see the comment from the Solid Waste Association of North America (SWANA) regarding the 600 tpd threshold, in EPA-HQ-OAR-2008-0508-2397.1, Excerpt 4).

Commenter Name: Kerry Kelly

Commenter Affiliation: Waste Management (WM)

Document Control Number: EPA-HQ-OAR-2008-0508-2360.1

Comment Excerpt Number: 7

Comment: WM believes it is important to note that small MSW combustion units with capacities below the 600 tons per day threshold are anticipating finalization of the new applicability threshold by the end of 2010. Indeed, EPA specifically states in the preamble that it intends to finalize these proposed revisions to the rule by the end of 2010, and recommends that sources calculate emissions and submit reports relying on these amendments:

EPA is planning to address the comments on these proposed amendments and publish the final amendments before the end of 2010. Therefore, reporters would be expected to calculate emissions and other relevant data for the reports that are submitted in 2011 using Part 98, as amended by this and the other revisions package (75 FR 33950), as finalized. 75 FR 48747.

Should EPA fail to promulgate these amendments by the end of 2010, units with less than 600 tons per day capacity will require a deferral of the requirement to use Tier 4 until January 1, 2012, so that they may have sufficient time to install and certify new Part 75 equipment.

Response: Please see EPA's response to comment in EPA-HQ-OAR-2008-0508-2397.1 excerpt 4 for a discussion of the timing of this rulemaking.

Commenter Name: John H. Skinner

Commenter Affiliation: Solid Waste Association of North America (SWANA)

Document Control Number: EPA-HQ-OAR-2008-0508-2397.1

Comment Excerpt Number: 4

Comment: The Solid Waste Association of North America (SWANA) appreciates EPA's decision to raise the applicability threshold for Tier 4 reporting from 250 tons per day to 600 tons per day. A WTE plant at 250 tpd has only 18-25% of the CO₂ emissions of the same sized fossil-fuel fired unit. 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, so this new threshold is much more appropriate.

Further we would like to point out that even under this new threshold a total of 27 waste-to-energy facilities, many of which are owned by local governments, would be required to use the more costly Tier 4 method. Since waste-to-energy facilities account for only 0.55 percent of the total CO₂e emissions from the combustion source sector, we question whether this economic burden on local government is justified and believe that the threshold could be set even higher. Should EPA fail to promulgate these amendments by the end of 2010, units with less than 600 tons per day capacity will require a deferral of the requirement to use Tier 4 until January 1, 2012, so that they may have sufficient time to install and certify new Part 75 equipment.

Response: EPA thanks the commenter for the input. We acknowledge that there are local government-owned waste-to-energy facilities that may still be subject to the Tier 4 requirements of the rule. The burden associated with this reporting was accounted for in the Regulatory Impact Analysis for the 2009 final rule. The purpose of amending the MSW threshold was to approximate the threshold for other stationary combustion units required to use Tier 4. As noted by the commenter, a 250 mmBtu/hr threshold applied to nominal MSW would translate into a mass rate threshold of approximately 600 tons / day. As such, we have concluded it is not appropriate to further raise the threshold above 600 tons of MSW per day.

These amendments will become effective prior to January 1, 2011, and the amendments will apply for reporting year 2010. Therefore, EPA has determined that there is no need to provide relief for units with a capacity of less than 600 tons of MSW per day.

Commenter Name: Ted Michaels

Commenter Affiliation: Energy Recovery Council (ERC)

Document Control Number: EPA-HQ-OAR-2008-0508-2393.1

Comment Excerpt Number: 5

Comment: The Energy Recovery Council (ERC) supports the proposed applicability threshold for requiring use of Tier 4 methodologies. The proposed 600 tons per day threshold will relieve smaller, primarily municipally-owned MSW combustor units from having to retrofit and install expensive new monitoring equipment that is inconsistent with the monitoring equipment required by the New Source Performance Standards for those units. At the same time, the 600 ton per day applicability threshold for MSW combustors is more stringent on the basis of non-

biogenic emissions per unit of heat input than the threshold applied to other combustors that fire 100% fossil fuel.

ERC believes it is important to note that small MSW combustion units with capacities below the 600 tons per day threshold are anticipating finalization of the new applicability threshold by the end of 2010. Indeed, EPA specifically states in the preamble that it intends to finalize these proposed revisions to the rule by the end of 2010, and recommends that sources calculate emissions and submit reports relying on these amendments:

“EPA is planning to address the comments on these proposed amendments and publish the final amendments before the end of 2010. Therefore, reporters would be expected to calculate emissions and other relevant data for the reports that are submitted in 2011 using Part 98, as amended by this and the other revisions package (75 FR 33950), as finalized. 75 FR 48747.”

Should EPA fail to promulgate these amendments by the end of 2010, units with less than 600 tons per day capacity will require a deferral of the requirement to use Tier 4 until January 1, 2012, so that they may have sufficient time to install and certify new Part 75 equipment.

Response: Please see EPA’s response to comment in EPA-HQ-OAR-2008-0508-2397.1 excerpt 4 for a discussion of the timing of this rulemaking and a comparison of the 600 tpd threshold to the 250 mmBtu/hr threshold.

Commenter Name: Eldon Lindt

Commenter Affiliation: Xcel Energy Inc.

Document Control Number: EPA-HQ-OAR-2008-0508-2374.1

Comment Excerpt Number: 7

Comment: The final rule requires the use of the Tier 4 calculation methodology for a unit that "has a maximum rated heated 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" (40 CFR §98.33(b)(4)(ii)(A)). Calculations using the Tier 4 methodology must begin January 1, 2011, if monitors have not been installed and certified prior to January 1, 2010 (40 CFR §98.33(b)(5)(ii)). The proposed rule increases the maximum rated heat input capacity for the Tier 4 calculation methodology to 600 tons per day of MSW.

Xcel Energy supports the proposed revision because it would eliminate the capital and O&M costs of continuous emissions monitoring systems (CEMS) on our six units that combust RDF. If the proposed rule becomes final, GHG emissions from these units will be calculated using the Tier 2 methodology. However, we are concerned that the timing of the proposed change will not be finalized soon enough for us to make a sound business decision prior to the current January 1, 2011, regulatory deadline for installing and certifying monitors. Because there is potential for delay in the finalization of the new limit, Xcel Energy asks that the revisions provide a six month extension for CEMS installation and certification for units affected by the 600 tons per day threshold change.

Response: Please see EPA's response to comment in EPA-HQ-OAR-2008-0508-2397.1 excerpt 4 for a discussion of the timing of this rulemaking.

Because we have finalized the amendments to allow units less than 600 tons of MSW per day to use the Tier 2 calculation procedures, we have concluded that additional relief is not needed for those units. Units greater than 600 tons of MSW per day have always been required to use the Tier 4 calculation procedures, and we did not propose otherwise in the August 11, 2010 proposal. Therefore, EPA has concluded that facilities with these larger units have known since promulgation of the 2009 final rule that these units must have their CEMS installed and certified by January 1, 2011.

Commenter Name: Stephen E. Woock

Commenter Affiliation: Weyerhaeuser Company

Document Control Number: EPA-HQ-OAR-2008-0508-2375.1

Comment Excerpt Number: 8

Comment: 98.33(b)(4)(ii)(B): This proposed revision fundamentally changes the requirement to use Tier 4 for units that burn solid fossil fuel or MSW as the primary or secondary fuel. This revision deletes the reference to the secondary fuel. A primary fuel has been defined in the proposed revisions as that fuel that provides the greatest percentage of annual heat input. This revision is important to units that burn a significant amount of biomass fuels and a small amount of supplemental coal for combustion control, due to the high moisture content often contained in the biomass, e.g. wet wood bark. Large combination boilers that burn wood residuals and some coal are common in the pulp and paper industry. To require a Tier 4 CO₂ CEM for this type of application is senseless and would result in unnecessary significant capital and facility resources to install and maintain a CO₂ CEM and gas flow monitoring system. As this revision illustrates, the purpose of this requirement was to capture combustion units that primarily burn coal or MSW, not combustion units that primarily burn biomass and a small amounts of coal. Weyerhaeuser supports this revision.

Response: EPA thanks the commenter for the input. We have finalized this provision, as proposed.

Commenter Name: Craig Holt Segall

Commenter Affiliation: Sierra Club Environmental Law Program et. al

Document Control Number: EPA-HQ-OAR-2008-0508-2398.1

Comment Excerpt Number: 15

Comment: Further, as stated in our comments on the proposed settlement agreements, EPA's proposal to raise the reporting threshold for MSW-burning facilities to use the Tier 4 methodology from 250 tons per day ("tpd") to 600 tpd is troubling. In this proposed rulemaking, EPA argues that the 600 tpd threshold is the approximate equivalent of the 250

mmBtu/hr heat requirement for other source categories. While this may be the case, we nonetheless renew our request in those previous comments.

EPA should still determine the emissions coverage it would lose from this change, as emissions coverage must ultimately be the metric for reporting rule decisions. We ask EPA to calculate that figure and report it in any final rulemaking. If EPA determines that the change will result in an unacceptably high emission coverage loss, it should not adopt the proposed change. [We generally agree that use of Tier 4 monitoring may result in more accurate emissions information, but that the information that would be made publicly available pursuant to EPA's proposed definition of "emission data" elements that would be required to be reported under lower tiers would be helpful in determining the impacts of GHG emissions with regard to different fuel types. However, evidence exists that use of MSW or other products that have reached the end of their useful lifetimes may create significant GHG emissions reductions when compared to fossil fuels or biomass. UN-Energy, Sustainable Bioenergy: A Framework for Decisionmakers, (Apr. 2007) ("Sustainable Bioenergy"), available at <http://esa.un.org/un---energy/pdf/susdev.Biofuels.FAO.pdf>. Despite these potential benefits, we nonetheless urge EPA to require the reporting of additional information that would be provided if a lower tier were being used, for example, amount of fuel and type and the carbon content of those fuels.]

Response: There is no loss in emissions coverage by this change. Units previously required to use CEMS to measure CO₂ emissions from MSW will now be required to use the Tier 2 methodology, based on steam production and boiler efficiency. We acknowledge that the lower tiers may result in a small loss in the accuracy of the data for smaller MWC units, but it is not our intent to impose undue burden on the smaller combustion units.

With respect to the comment that EPA should require Tier 4 units to report the same information that is reported by units using the lower tiers, this comment is outside the scope of the amendments proposed on August 11, 2010. Moreover, it is a broad concept that would require consideration in a more comprehensive manner across the entire rule.

EPA has undertaken a separate rulemaking effort to solicit comment on the treatment of confidential information under the Greenhouse Gas Reporting Program. Please refer to Proposed Confidentiality Determinations for Data Required Under the Mandatory Greenhouse Gas (docket EPA-HQ-OAR-2009-0924).

Commenter Name: Helen D. Silver

Commenter Affiliation: Clean Air Task Force et. al

Document Control Number: EPA-HQ-OAR-2008-0508-2403.2

Comment Excerpt Number: 11

Comment: EPA's proposal to raise the reporting threshold for MSW-burning facilities from 250 tons per day of MSW to 600 tons per day of MSW is troubling. See 75 Fed. Reg. at 48,757. EPA argues that the 600 ton per day requirement is closer to the 250 mmbtu/hr heat input reporting threshold for other reporting sources. Even if this is so, EPA should still determine the emissions

coverage it would lose from this change, as emissions coverage must ultimately be the metric for reporting rule decisions. We ask EPA to calculate that figure and report it in any final rulemaking. If EPA determines that the change will result in an unacceptably high emission coverage loss, it should not adopt the proposed change.

Response: Please see EPA's response to comment in EPA-HQ-OAR-2008-0508-2398.1 excerpt 15.

CH₄ and N₂O emissions

Commenter Name: Mike Stroben

Commenter Affiliation: Duke Energy

Document Control Number: EPA-HQ-OAR-2008-0508-2354.1

Comment Excerpt Number: 1

Comment: The Methane (CH₄) and Nitrous Oxide (N₂O) Calculation Simplification Available to Part 75 CEMs Units Should Also Be Available to Subpart C Tier 4 Units

On page 48791 of EPA's proposed rule, EPA proposes to simplify the record keeping necessary to calculate CH₄ and N₂O emissions in §98.33(c)(4)(ii) for units using part 75 CEMs calculations by adding the following paragraph:

(B) For a unit that uses CEMS to monitor hourly heat input according to part 75 of this chapter, the value of (HI)_A obtained from the electronic data reports under §75.64 of this chapter may be attributed exclusively to the fuel with the highest F-factor, when the reporting option in 3.3.6.5 of appendix F to part 75 of this chapter is selected and implemented.

As the calculated emissions of GH₄ and N₂O from these units is insignificant and well within the margin of error for the CEMs equipment, no matter how it is calculated, compared to the quantity of CO₂ emitted, this is a reasonable action that Duke Energy supports. It would also be reasonable for EPA to provide the same simplification to Tier 4 units. Instead, EPA is proposing the following:

(G) For Tier 4 units, use the best available information (e.g., fuel feed rate measurements, fuel heating values, engineering analysis) to estimate the value of (HI)_A for each type of fuel.

This requirement would force Tier 4 operators to track the fuel use of each combustion source when the CEMs are already providing sufficiently accurate emissions data. Many industrial sites have Tier 4 sources that fire very much like a Subpart D electric generating units. There is no reason why Tier 4 units should not be allowed to use the same simplifying CH₄ and N₂O provision. If Tier 4 units are not allowed to use the paragraph (B) provision they will be forced to track or estimate fuel use for several different fuels on a unit by unit basis with no associated increase in the accuracy of the CH₄ or N₂O emissions calculations.

Duke Energy requests that EPA make §98.33(c)(4)(ii)(B) available to Tier 4 units that implement a fixed f-factor in their CEMs calculations similar to the reporting option in 3.3.6.5 of appendix F to part 75.

Response: The final rule does not incorporate the commenter's suggestion. We can audit the electronic monitoring plans of Part 75 units to determine the type(s) of fuel combusted and the purpose of each fuel (e.g., primary fuel, secondary fuel, startup fuel). We can then apply a filter to identify multi-fuel units that report a single F-factor for all unit operating hours. This information can help us identify Part 75 units that may be misapplying the worst-case F-factor provision. We do not have similar audit capability for Tier 4 units.

We note, however, that requiring Tier 4 units to report CH₄ and N₂O emissions by fuel type is not overly burdensome, since sources are allowed to use the best available information to determine fuel consumption and fuel-specific heat input. Any flow meters or other instruments used to determine fuel usage are not subject to the calibration requirements of 40 CFR 98.3(i) or the quality assurance requirements of 40 CFR 98.34. The best available information may also be an engineering analysis.

Commenter Name: Michael Hannan
Commenter Affiliation: Williams Olefins LLC
Document Control Number: EPA-HQ-OAR-2008-0508-2357.1
Comment Excerpt Number: 29

Comment: In §98.33(c)(2), the reference to the Tier 1 or Tier 3 calculation is incorrect and should be replaced by reference to the Tier 2 calculation.

Response: A correction to the reference the commenter cites was included in the proposed rule and has been finalized. No further changes need to be made.

Commenter Name: Caitlin Post
Commenter Affiliation: Southern Company
Document Control Number: EPA-HQ-OAR-2008-0508-2377.1
Comment Excerpt Number: 3

Comment: EPA is proposing changes to 40 CFR 98.33(c)(4) to allow flexibility in determining the cumulative annual heat input needed to calculate CH₄ and N₂O using equation C-10. EPA is proposing to allow units subject to subpart D that measure their hourly heat input values based on Section 3.3.6.5 of Part 75 appendix F, which bases all hourly heat input values on the "worst-case" or highest F-factor for any fuel combusted in the unit, to use this same heat input in equation C-10. Southern Company supports this proposal because it is consistent with other information already being reported to EPA and will reduce the reporting burden for units that use this method.

Response: EPA thanks the commenter for the input. We have finalized the amendments, as proposed.

Commenter Name: Lauren E. Freeman

Commenter Affiliation: Utility Air Regulatory Group (UARG)

Document Control Number: EPA-HQ-OAR-2008-0508-2388.1

Comment Excerpt Number: 9

Comment: VI. Methane (CH₄) and Nitrous Oxide (N₂O) Calculations

As promulgated, § 98.33(c) requires units that monitor and report heat input year-round basis under Part 75 to calculate CH₄ and N₂O based on the “cumulative annual heat input from [each] fuel, derived from the electronic data reports required under § 75.64” and fuel-specific emission factors for CH₄ and N₂O from Table C–2. As UARG explained in its Reconsideration Petition, this provision is based on the misconception that Part 75 units are necessarily recording and reporting heat input for each fuel combusted. The current rule also limits reporting to fuels combusted during “normal operation,” but does not define “normal operation” or explain how the heat input from non-normal operation would be calculated and excluded from the total annual heat input reported under Part 75. UARG further explained that, under Part 75, most sources that use oil or gas for startup, or that combust a small amount of secondary fuel with a lower F-factor (e.g., use oil for flame stabilization) exercise an option in Part 75 that allows the source to use the “worst case” F-factor to report heat input from secondary fuels (e.g., calculate heat input assuming only coal was combusted). A rule that requires Part 75 sources that monitor with CEMS to exclude startup operations from GHG reporting, or to derive fuel specific heat input values from the Part 75 report, would require collection and reporting of information that are different from what is currently reported under § 75.64.

To address UARG’s concerns, EPA proposes to remove references to “normal operation” from § 98.33(c)(4)(i) and (ii) and to allow additional options for Part 75 sources that are unable to determine the heat input contribution of a specific fuel from the Part 75 quarterly reports because, for example, they have exercised the “worst-case” F-factor option for reporting under Part 75. 75 Fed. Reg. at 48,758. All of the options provided in EPA’s proposed rule are reasonable and necessary to allow Part 75 sources to calculate and report CH₄ and N₂O using their Part 75 heat input data. EPA should finalize the revisions as proposed.

Response: EPA thanks the commenter for the input. We have finalized the amendments as proposed.

Biogenic CO₂ emissions

Commenter Name: Rhea Hale

Commenter Affiliation: American Forest & Paper Association (AF&PA)

Document Control Number: EPA-HQ-OAR-2008-0508-2382.1

Comment Excerpt Number: 2

Comment: The current method for calculating the biogenic share of CO₂ emissions for Part 75 sources is burdensome and should be amended. The methods defined in the final reporting rule require that facilities calculate the fossil portion via equation C-13 and C-14 and the various subparagraphs of 40 CFR 98.33(e)(2) and subtract it from the CEM total resulting in the biogenic share. For those facilities using a small amount of biomass, and a Part 75 monitor, the requirement to calculate a higher heating value via fuel sampling analysis is extremely burdensome and could produce inconsistencies between the fossil fuel emission calculation and the CEMs reading. The prescribed method is also inflexible should a facility wish to burn biomass at a future point in time but has not completed prior fuel sampling of its fossil fuel. Instead, EPA should allow Part 75 sources to calculate either their biogenic or their fossil fuel portions and eliminate the fuel sampling requirement, replacing it with a default higher heating value. These default values are provided by EPA in Table C-1 of Subpart C. EPA could set the threshold for this HHV default selection to when biomass comprises less than 50% of the annual heat input. Also note that fuels not listed in Table C-1 are exempt if they provide less than 10% of the total heat input.

These changes would allow Part 75 sources that are not predominantly burning biomass to report biogenic CO₂ separately with minimal additional effort to their Part 75 CO₂ CEMS reporting obligations under the Mandatory Reporting Rule. This will eliminate potential discrepancies involved with using two different methods when fossil fuel is the predominant portion of the CEMS total and will provide more flexibility for reporting entities related to fuel mix. Only for facilities burning truly incidental amounts of biomass (e.g. less than 5% of total heat input) should separate reporting of biogenic emissions be optional.

In addition, since Subpart D Part 75 method users are expected to select the biomass fuel calculation option when they are firing only relatively small amounts of biomass, the rule language could be modified to allow those Subpart D reporters to use default higher heating values for biomass in their Equation C-13 calculation without any appreciable loss of accuracy.

In formal implementation-related questions posed to EPA following the finalization of the Reporting Rule, the American Forest & Paper Association (AF&PA) requested that facilities be allowed to calculate either the biogenic share of the CEMS total or the fossil portion at their discretion. Sean Hogan of EPA responded that EPA would consider this proposed change. See the following EPA responses to AF&PA questions dated February 16, 2010:

“Question 14: EPA should allow unit that is using Tier 4 and combusts a combination of fossil and biomass fuels to back out the biomass for CO₂ calculations. The rule states that in order to determine the amount of biogenic CO₂ emitted from a combination combustion unit the fossil fuel portion of the total CO₂ is calculated (Equation C-13) and subtracted from the total CO₂ as read by the CEMS. We propose that units should have the option to calculate the biogenic CO₂ using the same methodology as Equation 13. The amount of biomass fuel has to be quantified for CH₄ and N₂O calculations and a fuel specific default F-factor for Bark and Wood residue is available from Table 1 in section 3.3.5 of Appendix F to 40 CFR part 75. Alternatively, a facility

would have the option to determine a site-specific value as outlined under section 3.5.6 of Appendix F to 40 CFR part 75.

Response: Thank you for your proposal. EPA will give this further consideration.”

Proposed Alternative Approach:

Sources that combust both biomass and fossil fuels and use a (Tier 4) CO₂ CEM currently are required to calculate the fossil CO₂ and determine the biomass fuel CO₂ by difference (i.e. CEM CO₂ minus fossil CO₂). Under this alternate approach, sources would be allowed to choose either their biomass or their fossil fuel use to determine the calculated CO₂ emissions using the same methodology as the current Equation C-13. This approach is reasonable since the amount of biomass fuel used has to be quantified for CH₄ and N₂O calculations anyway and a fuel specific default F-factor for Bark and Wood residue is available from Table 1 in section 3.3.5 of Appendix F to 40 CFR Part 75. Alternatively, a facility would have the option to determine a site-specific value as outlined under section 3.5.6 of Appendix F to 40 CFR Part 75.

To allow the use of either calculating the fossil fuel CO₂ or biomass CO₂, a small change to the current Equation C-13 can be made. The current Equation C-13 is as follows:

$$V_{ff} = [\text{Fuel} * F_c * \text{HHV}] / 1,000,000 \text{ (Eq. C-13)}$$

Where:

V_{ff} = Annual volume of CO₂

Fuel = Total quantity of the fossil fuel combusted

F_c = Fuel-specific carbon based F-factor

HHV = High heat value of the fossil fuel

1,000,000 = Conversion factor, Btu per mmBtu

Equation C-13 calculates the annual CO₂ volume from the fossil fuels. To allow the calculation of CO₂ for any fuel, the reference to “fossil fuels” should be changed to “fuels combusted.” Therefore, Equation C-13 stays the same, but the definitions are now:

V_{fc} = Annual volume of CO₂ for fuels combusted

Fuel = Total quantity of the fuels combusted

F_c = Fuel-specific carbon based F-factor

HHV = High heat value of the fuels combusted

1,000,000 = Conversion factor, Btu per mmBtu

Corresponding rule language text changes to calculate the correct CO₂ fraction would need to be made in 40 CFR 98.33(e)(2)(iii) and (iv). For example, at 98.33(e)(2)(iii) at the two places where the words “fossil fuel” currently exist they could be replaced with the phrase “either fossil fuel or biomass.”

Response: Please see Section II.C in the preamble to the final rule amendments, for EPA’s rationale regarding biogenic CO₂ reporting for Part 75 units

The recommended change to the calculation methodology in §98.33(e)(2) is deemed to be unnecessary, in view of the fact that the final rule provides two simplified procedures for quantifying biogenic CO₂ emissions at facilities with part 75 units. First, we have expanded the use of the Tier 1 methodology under §98.33(e)(1) to include units that use CEMS. Second, today's rule provides a method in §98.33(e)(6) that allows biogenic CO₂ emissions to be calculated based on the heat input data available in the annual electronic reports submitted under Part 75, supplemented, if necessary, with other available information. The calculation method proposed by the commenter is significantly more complicated than either of these two methods, and could only be used for the two biomass fuels listed in Table 1 of 40 CFR Part 75, Appendix F, section 3.3.5 (i.e., for wood residue and bark). For more information on the final methods for quantifying CO₂ emissions from biomass combustion, please refer to section II.G of the preamble.

Commenter Name: Brian Gasiorowski

Commenter Affiliation: Lafarge North America

Document Control Number: EPA-HQ-OAR-2008-0508-2401.1

Comment Excerpt Number: 1

Comment: EPA has clearly stated its desire to provide facilities with added flexibility with respect to mandatory requirements for separate reporting of biogenic CO₂ emissions. EPA states on page 48759 of the preamble:

"In general, biogenic CO₂ emissions reporting would be required only for the combustion of the biomass fuels listed in Table C-1 and for municipal solid waste (which consists partly of biomass and partly of fossil fuel derivatives.)

We are proposing to amend 40 CFR 98.33(e) to describe three cases in which units that combust biomass would not need to report biogenic CO₂ emissions separate from total CO₂ emissions."

We are concerned that none of the above three exclusionary cases would provide relief to a cement kiln operator using a CO₂ CEMs to measure the total combustion and process emissions from a cement kiln that is using some relatively small amount of an alternative fuel that still fits within EPA's proposed definition of "municipal solid waste."

As EPA is aware the cement industry plays a significant positive role in promoting resource conservation and recovery through use of a broad range of byproducts as alternative fuels. These byproducts include materials such as woods, papers, plastics, carpets, baby diapers, animal and agricultural byproducts, asphalt shingles, tires, landfill gas, auto shredder fluff, and many others. The proposed rule language provides flexibility such that in many cases a cement kiln operator using CO₂ CEMs to determine the total CO₂ emission from the cement kiln is not obligated to report biogenic CO₂ emissions separately. In these cases, the separate reporting of biogenic CO₂ emissions would be optional. However, we are concerned that in a more limited number of cases a cement kiln operator using an alternative fuel meeting the definition of "MSW" under this rule

would be obligated to separately measure and report biogenic CO₂ emissions even if only a very small amount of the "MSW" fuel were being used with relatively small biogenic emissions.

We propose two changes to the language of the rule which would ensure that cement kiln operators using relatively small amounts of "MSW" are not obligated to separately report the small amount of biogenic emissions from combustion of the MSW. In these cases the facility would include the biogenic CO₂ emissions with the total CO₂ emissions determined by the CEMs. These two proposed changes are as follows:

1. Adding a definition for "plastics" along with a minor change to the definition of MSW to clarify that any plastics separated from MSW are not included within the MSW definition.
2. Adding a sub-paragraph under 98.33(e)(3) to make reporting of biogenic CO₂ emissions optional for cases where less than 10% biomass fuel is used even if CO₂ CEMs are being used.

Response: EPA has revised the definition of municipal solid waste (MSW) in §98.6, which we have concluded addresses the commenter's concern, by specifying that materials separated from MSW and combusted separately (such as plastics) are not classified as MSW. We have determined that this definition change addresses the commenter's concern, and therefore, a definition of plastics does not need to be added to the rule at this time. .

We have not incorporated the commenter's suggestion to make biogenic CO₂ reporting optional for sources that burn less than 10% biomass. However, recognizing that the use of ASTM Methods D7459-08 and D6866-08 each quarter can impose a significant cost burden on sources that burn small amounts of partially biogenic fuels such as MSW and tires, we have added a provision to the final rule that allows sources that derive 10 percent or less of their heat input from MSW and/or tires to calculate biogenic CO₂ emissions using the Tier 1 methodology together with fuel-specific default biogenic percentages. See section II.G of the preamble to the final rule amendments for further information.

Commenter Name: Stephen E. Woock

Commenter Affiliation: Weyerhaeuser Company

Document Control Number: EPA-HQ-OAR-2008-0508-2375.2

Comment Excerpt Number: 3

Comment: A Proposed Solution. In overview, sources would still report biogenic CO₂ completely separate from other GHG emissions as in the current rule, but CO₂ CEMS users would have the option as to which fuel type -fossil fuel or biomass fuel-to use to determine the portion of their CO₂ emissions to subtract from their CEMS total to get the balance or CO₂ for the other fuel type. Part 75 CO₂ CEMS users subject to Subpart D would also be allowed to use a default higher heating value (HHV) for their biomass fuel when their biomass fuel use is less than 50% of their total heat input. These changes should allow the UARG members who are not

predominantly burning biomass to report biogenic CO₂ separately with minimal additional effort to their Part 75 CO₂ CEMS reporting obligations under the Mandatory Reporting Rule. Current Rule Under current rule provisions, sources that combust both biomass and fossil fuel and use a CO₂ CEMS are required to calculate the fossil CO₂ and determine the biomass fuel CO₂ by difference (Le., CEM CO₂ minus fossil CO₂).

Alternate Approach. Under this alternate approach, sources would be allowed to choose either their biomass or the fossil fuel use to determine the calculated CO₂ emissions using the same methodology as the current Equation C-13. This approach is reasonable since the amount of biomass fuel used has to be quantified for CH₄ and N₂O calculations anyway and a fuel specific default F-factor for Bark and Wood residue is available from Table I in section 3.3.5 of Appendix F to 40 CFR Part 75. Alternatively, a facility would have the option to determine a site-specific value as outlined under section 3.5.6 of Appendix F to 40 CFR Part 75. In addition, since Subpart D Part 75 method users are expected to select the biomass fuel calculation option when they are firing only relatively small amounts of biomass, the rule language could be modified to allow those Subpart D reporters to use default higher heating values for biomass in their Equation C-13 calculation without any appreciable loss of accuracy. These default values are provided by EPA in Table C-I of Subpart C. EPA could set the threshold for this HHV default selection to when biomass comprises less than 50% of the annual heat input. Also note that fuels not listed in Table C-I are exempt if they provide less than 10% of the total heat input. To allow the use of either calculating the fossil fuel CO₂ or biomass CO₂, a small change to the current Equation C-13 can be made. The current Equation C-13 is as follows:

$$V(ff) = [Fuel * F(c) + HHV] 10^6 \text{ (Eq. C-13)}$$

Where:

V(ff)= Annual volume of CO₂

Fuel = Total quantity of the fossil fuel combusted

Fc = Fuel-specific carbon based F-factor

HHV = High heat value of the fossil fuel

10⁶= Conversion factor, Btu per mmBtu

Equation C-13 calculates the annual CO₂ volume from the fossil fuels. To allow the calculation of CO₂ for any fuel, the reference to "fossil fuels" should be changed to "fuels combusted."

Therefore, Equation C-13 stays the same, but the definitions are now:

V(fc) = Annual volume of CO₂ (Note V(fc) = volume of CO₂ for fuels combusted (fc)) (Change V(ff) to V(fc))

Fuel = Total quantity of the fuels combusted (Change fossil fuel to fuels)

Fc = Fuel-specific carbon based F-factor

HHV = High heat value of the fuels combusted (Change fossil fuel to fuels combusted)

10⁶= Conversion factor, Btu per mmBtu

Corresponding rule language text changes to calculate the correct CO₂ fraction would need to be made in 40 CFR 98.33(e)(2)(iii) and (iv). For example, at 98.33(e)(2)(iii) at the two places where the words "fossil fuel" currently exist they could be replaced with the phrase "either fossil fuel or biomass."

In summary, allowing the source to select the fuel type to calculate the CO₂ will still achieve the accuracy standards in the GHG MRR while lessening the unnecessary monitoring and reporting burden for Subpart D sources that use CO₂ CEMS and predominantly burn fossil fuels.

Response: See the response to comment EPA-HQ-OAR-2008-0508-2382.1, Excerpt 2.

Commenter Name: Helen D. Silver

Commenter Affiliation: Clean Air Task Force et. al

Document Control Number: EPA-HQ-OAR-2008-0508-2403.1

Comment Excerpt Number: 3

Comment: We urge EPA to require that the reporter use the tier method that will provide the most accurate information regarding the amount and type of biomass used and its carbon content – presumably the Tier 3 methodology as it proposes. Importantly, for purposes of determining the types of biomass being combusted and the amount of emissions, under EPA’s proposed definition of “emission data”, EPA would make available all of the inputs required to make these calculations, which would include at least the fuel type and fuel amount. This would provide the public and policymakers with important information regarding the types and amount of biomass being used. Thus, in conjunction with the evolving scientific evidence, the public and policymakers will be able to more accurately assess the GHG impacts of biomass use. EPA further proposes to amend the provisions of section 98.33(e) by removing the CEMS restriction on the use of Tier 1 reporting to determine biogenic emissions contained in section 98.33(e)(1). EPA rationalizes that “[t]here is no technical basis for this restriction provided that biomass consumption can be accurately quantified.” While that may be the case with respect to the rule as it exists [A fact that we do not concede], we would urge EPA to take this opportunity to strengthen the reporting requirements. EPA should provide that the source category must determine its biogenic CO₂ emissions using the tier that applies to that unit. For instance, source categories that are required to use Tier 3 methodology to calculate their other GHG emissions would be required to use Tier 3 to determine their biogenic CO₂ emissions.

In general, we agree with EPA that section 98.33(e)(2) needs to be revised to more accurately capture the amount of CO₂ emissions from biomass combustion. We also agree that use of this methodology from facilities whose monitoring also includes process and/or sorbent CO₂ emissions and emissions from the combustion of MSW could lead to an inaccurate accounting of biogenic CO₂ emissions. However, we again think that this is an opportunity to strengthen this rule. Therefore we propose that EPA amend the rule to require that a facility that is disqualified from using the methodology set forth in section 98.33(e)(2), as proposed, must use the Tier 3 methodology to calculate its biogenic CO₂ emissions. Again, as explained above, this would provide the public with useful information not only about the amount of biogenic CO₂ emissions from source categories, but as to the type and amount of biomass used.

Response: The commenter states that Tier 3 rather than Tier 1 should be used to calculate CO₂ emissions from biomass combustion, for units with CEMS that cannot use the calculation method in §98.33(e)(2), because Tier 3 will provide information on the type and amount of biomass fuel(s) combusted. In fact, Tier 1 provides the same basic information as Tier 3, regarding the fuel type and the amount of fuel combusted (see §§98.36(b)(4), 98.36(e)(2)(i), and 98.36(e)(2)(iv)(A)). The difference between the two Tiers is that Tier 1 uses a default HHV and a default CO₂ emission factor in the emissions calculations, whereas Tier 3 requires periodic determination of the carbon content of the fuel. Also, the Tier 3 QA/QC requirements for quantifying fuel consumption are generally much more rigorous than those for Tier 1.

Although Tier 3 is likely to provide more accurate data than Tier 1, particularly for a fuel that has a significantly variable heating value or carbon content, we are not imposing the added burden of Tier 3 fuel sampling and QA/QC requirements on units with CEMS, particularly when the method in §98.33(e)(2) to calculate biogenic CO₂ emissions cannot be used. Sources always have the option to use Tier 3 instead of Tier 1, if greater accuracy is desired, but the additional burden is not warranted at this time. Further, we would note that such a decision does not affect the uncertainty of the overall emissions estimate that was obtained from the CEMS, but only the allocation of emissions between biogenic and fossil. In view of these considerations, the commenter's suggestion has not been incorporated into the final rule.

Commenter Name: Brian Gasiorowski

Commenter Affiliation: Lafarge North America

Document Control Number: EPA-HQ-OAR-2008-0508-2401.1

Comment Excerpt Number: 4

Comment: Proposed exclusion for cases where MSW is less than 10% of Annual Heat Input
There are cases in which a cement kiln operator may use an MSW-derived fuel in small amounts of just a few percent of a kiln's annual heat input. We believe that in these cases the quarterly - or more frequent - stack gas sampling and testing is unwarranted relative to the small amount of biogenic CO₂ emissions which would be required to be reported separately. We propose adding a sub-paragraph under 98.33(e)(3) to make reporting of biogenic CO₂ emissions optional for cases where less than 10% biomass fuel is used even if CO₂ CEMs are being used.

Response: See the response to comment EPA-HQ-OAR-2008-0508-2401.1, Excerpt 1.

Commenter Name: Bryan Brendle

Commenter Affiliation: Portland Cement Association

Document Control Number: EPA-HQ-OAR-2008-0508-2399.1

Comment Excerpt Number: 7

Comment: EPA states on page 48759 of the preamble:

“In general, biogenic CO₂ emissions reporting would be required only for the combustion of the biomass fuels listed in Table C-1 and for municipal solid waste (which consists partly of biomass and partly of fossil fuel derivatives.)

We are proposing to amend 40 CFR 98.33(e) to describe three cases in which units that combust biomass would not need to report biogenic CO₂ emissions separate from total CO₂ emissions.” We are concerned that none of the three exclusionary cases would provide relief to a cement kiln operator using a CO₂ CEMs to measure the total combustion and process emissions from a cement kiln that is using some relatively small amount of an alternative fuel that still fits within EPA’s proposed definition of “municipal solid waste.”

As EPA is aware, the cement industry plays a significant positive role in promoting resource conservation and recovery through use of a broad range of byproducts as alternative fuels. These byproducts include materials such as woods, papers, plastics, carpets, baby diapers, animal and agricultural byproducts, asphalt shingles, tires, landfill gas, auto shredder fluff, and many others. The proposed rule language provides flexibility such that in many cases any biogenic CO₂ emissions are not obligated to be reported separately from a cement kiln operator using CO₂ CEMs to determine the total CO₂ emission from the cement kiln. Instead, in the cases reporting of biogenic CO₂ emissions would be optional. However, we are concerned that is a more limited number of cases a cement kiln using an alternative fuel meeting the definition of “MSW” under this rule would be obligated to separately determine and report biogenic CO₂ emissions even if only a very small amount of the “MSW” fuel were being used with relatively small biogenic emissions.

We propose two changes to the language of the rule which would ensure that cement kiln operators using relatively small amounts of “MSW” are not obligated to separately report the small amount of biogenic emissions from combustion of the MSW. In these cases the facility would include the biogenic CO₂ emissions with the total CO₂ emissions determined by the CEMs. These two proposed changes are as follows:

1. Adding a definition for “plastics” along with a minor change to the definition of MSW to clarify that any plastics separated from MSW are not included within the MSW definition.
2. Adding a sub-paragraph under 98.33(e)(3) to make reporting of biogenic CO₂ emissions optional for cases where less than 10% biomass fuel is used even if CO₂ CEMs are being used.

Response: See the response to comment EPA-HQ-OAR-2008-0508-2401.1, Excerpt 1.

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2008-0508-2383.1

Comment Excerpt Number: 8

Comment: Several petroleum industry companies have requested clarifications to the estimation methodology for the biogenic portion of GHG emissions for small incinerator units, typically remotely located, such that the data collection burden and amount of emissions would be balanced. As the technical corrections to Subpart C, did not address this issue adequately, API members would like to raise this issue again and provide an example to support our suggestions.

The oil and gas industry operates small co-fired batch incinerators located at remote facilities to burn on-site Municipal Solid Waste (MSW) classified trash and waste. 40 CFR 98.34(d) requires facilities that combust MSW to determine the biogenic portion of the CO₂ emissions using ASTM 06866-08 (analysis) and ASTM 07459-08 (sampling) each quarter when MSW is combusted.

These types of units typically co-fire natural gas and MSW the entire time they are in use and operate in batch mode. The Technical Revisions to Part 98 in the Federal Register on August 11, 2010, provide clarification on the issue of exhaust gas testing for co-fired units. 40 CFR 98.34(d) requires determination of the biogenic portion of the CO₂ emissions for units when MSW is the only fuel with a biogenic portion component combusted in the unit. This would be applicable to the typical small remote location incinerators found in the industry.

One API member company performed sampling on an incinerator at an Alaska North Slope operation in June 2010. The samples were taken during co-firing of MSW and natural gas, as this is the only mode in which the incinerator is able to operate. The biogenic portion of the exhaust was 28 percent. Applying this biogenic portion to the sum of the emissions from natural gas (using Tier 1) and the MSW (using Tier 1) for the total 2009 fuel use (as an example calculation, 2010 year will not vary greatly) yields the following results: [See submittal for data tables provided by commenter showing the portion of biogenic CO₂ emissions from MSW combustion]

Several options would be preferable to the current requirements for these small sources. In order of preference these are:

(1) Make reporting of the biogenic portion of incinerator CO₂ emissions optional for sources whose projected annual emissions from MSW are less than a certain threshold (e.g. 5,000 tonnes). Provide a default biogenic percentage, such as 30% for the sources who choose not to perform the testing.

(2) If EPA feels that testing is necessary, regardless of the magnitude of emissions from the source, allow sources to perform one-time testing for biogenic content and then use the data for current and future reporting. A periodic test (once every 5 years) to reconfirm the biogenic portion would be reasonable.

The basis of this request to modify the current requirements in Part 98 is on the cost to perform the testing vs. the amount of biogenic emissions quantified. The cost of the June 2010 test highlighted above was approximately \$11,000. Subsequent tests are expected to be on the order of \$5,000-\$7,000 each. Therefore, it will cost approximately \$20,000-\$30,000 per year per facility, indefinitely, to quantify approximately 400 tonnes of biogenic CO₂ emissions annually from a single small batch, co-fired incinerator. For a regulation with an applicability threshold of

25,000 metric tons, the cost is not reasonable in relation to the mass of emissions it quantifies. Use of a default biogenic factor would be a far more reasonable assessment method, and any error introduced by use of a default would only be on the order of tens or hundreds of tonnes. This magnitude of error is consistent with the use of the default factors of Tiers 1 and 2, which are considered reasonable by EPA. Additionally, the biogenic component of emissions from these types of units is not expected to vary significantly.

API requests that the requirement to determine the biogenic portion of CO₂, through sampling and analysis, for the exhaust from these small incinerators should be optional and a simplified and limited protocol provided to estimate the biogenic portion of the emissions. API requests further technical correction to the provisions of 98.34(d) to allow those options.

Response: Please see Section II.G of the preamble to the final rule amendments for the response to this comment.

Commenter Name: Bryan Brendle
Commenter Affiliation: Portland Cement Association
Document Control Number: EPA-HQ-OAR-2008-0508-2399.1
Comment Excerpt Number: 10

Comment: Proposed exclusion for cases where MSW is less than 10 percent of Annual Heat Input. There are cases in which a cement kiln operator may use an MSW-derived fuel in small amounts of just a few percent of a kiln's annual heat input. We believe that in these cases the quarterly – or more frequent – stack gas sampling and testing is unwarranted relative to the small amount of biogenic CO₂ emissions which would be reported separately. We propose adding a sub-paragraph under 98.33(e)(3) to make reporting of biogenic CO₂ emissions optional for cases where less than 10% biomass fuel is used even if CO₂ CEMs are being used.

Response: See the response to comment EPA-HQ-OAR-2008-0508-2401.1, Excerpt 1.

Commenter Name: Craig Holt Segall
Commenter Affiliation: Sierra Club Environmental Law Program et. al
Document Control Number: EPA-HQ-OAR-2008-0508-2398.1
Comment Excerpt Number: 11

Comment: C. Amendments to Methodology for Calculating Biogenic CO₂ Emissions

EPA proposes various revisions to the 40 C.F.R. § 98.33, and in particular subsection (e) of that provision. As an initial matter, we oppose any proposed amendment that would exempt any source category from separately reporting its biogenic CO₂ emissions (including those emissions

which may result from the combustion of tires and other municipal solid waste (“MSW”).[Specifically we oppose proposed section 98.33(a)(5)(iv) and 98.33(e).]

EPA proposes to amend § 98.33(e) of the rule to address reporting of biogenic CO₂ emissions in the event that the rule does not provide an HHV or default CO₂ emission factor for a specific type of biofuel. Facilities that use fuels for which default values are not provided may face some burden in calculating biogenic CO₂ emissions. Nonetheless, we urge EPA to require separate reporting of biogenic CO₂ emissions whenever possible. Therefore, EPA should not provide, as proposed, that use of CEMS would exempt a source from this separate reporting requirement. Once again, knowing the amount of biogenic CO₂ emissions is important from a policy perspective regardless of the monitoring methodology used. Therefore, we urge EPA to require that the reporter use the methodological tier that will provide the most accurate information regarding the amount and type of biomass used and its carbon content – presumably the Tier 3 methodology as it proposes.

Importantly, for purposes of determining the types of biomass being combusted and the amount of emissions, under EPA’s proposed definition of “emission data”, EPA would make available all of the inputs required to make these calculations, which would include at least the fuel type and fuel amount. This would provide the public and policymakers with important information regarding the types and amount of biomass being used. Thus, in conjunction with the evolving scientific evidence, the public and policymakers will be able to more accurately assess the GHG impacts of biomass use.

Response: The final rule allows only two exceptions to the requirement to separately report biogenic CO₂ emissions: (1) For Part 75 units, the reporting is optional for 2010, but becomes mandatory for the 2011 reporting year; and (2) the reporting is optional for the combustion of tires. For more information on EPA’s rationale regarding biogenic CO₂ emissions reporting, see Sections II.C.2 and II.G of the preamble to the final rule amendments.

Please see also the response to comment EPA-HQ-OAR-2008-0508-2403.1, excerpt 3.

Commenter Name: Craig Holt Segall

Commenter Affiliation: Sierra Club Environmental Law Program et. al

Document Control Number: EPA-HQ-OAR-2008-0508-2398.1

Comment Excerpt Number: 12

Comment: EPA further proposes to amend the provisions of section 98.33(e) by removing the CEMS restriction on the use of Tier 1 reporting to determine biogenic emissions contained in section 98.33(e)(1). EPA rationalizes that “[t]here is no technical basis for this restriction provided that biomass consumption can be accurately quantified.” While that may be the case with respect to the rule as it exists, [A fact that we do not concede.] we would urge EPA to take this opportunity to strengthen the reporting requirements. EPA should provide that the source category must determine its biogenic CO₂ emissions using the tier that applies to that unit. For

instance, source categories that are required to use Tier 3 methodology to calculate their other GHG emissions would be required to use Tier 3 to determine their biogenic CO₂ emissions.

Response: Please see response to comment EPA-HQ-OAR-2008-0508-2403.1, excerpt 3.

Commenter Name: Craig Holt Segall

Commenter Affiliation: Sierra Club Environmental Law Program et. al

Document Control Number: EPA-HQ-OAR-2008-0508-2398.1

Comment Excerpt Number: 13

Comment: In general, we agree with EPA that section 98.33(e)(2) needs to be revised to more accurately capture the amount of CO₂ emissions from biomass combustion. We also agree that use of this methodology from facilities whose monitoring also includes process and/or sorbent CO₂ emissions and emissions from the combustion of MSW could lead to an inaccurate accounting of biogenic CO₂ emissions. However, we again think that this is an opportunity to strengthen this rule. Therefore we propose that EPA amend the rule to require that a facility that is disqualified from using the methodology set forth in section 98.33(e)(2), as proposed, must use the Tier 3 methodology to calculate its biogenic CO₂ emissions. Again, as explained above, this would provide the public with useful information not only about the amount of biogenic CO₂ emissions from source categories, but as to the type and amount of biomass used.[In fact, EPA may want to consider requiring a source category to determine its biogenic CO₂ emissions even if a facility uses CEMS as this would require, pursuant to EPA's proposed definition of "emission data," the amount and type of biomass that is used publicly available.]

Response: See the response to comment EPA-HQ-OAR-2008-0508-2403.1, Excerpt 3.

Monitoring and QA/QC requirements

Commenter Name: Jeff Applekamp

Commenter Affiliation: Gas Processors Association (GPA)

Document Control Number: EPA-HQ-OAR-2008-0508-2402.1

Comment Excerpt Number: 2

Comment: Natural Gas Standard Conditions (Preamble page 48768)

EPA acknowledges in the Preamble (page 48768) that "the oil and gas industry and other hydrocarbon processing facilities commonly express gaseous volumes using 60 F as the standard temperature. Thus, many existing flow monitors for gaseous feedstocks and products at petrochemical facilities may be programmed to output volumes at standard conditions of 60 F. It is impractical and unnecessary to either reprogram these monitors to provide volumes corrected to standard conditions at 68 F or to require reporters to convert the output volumes from one set of standard conditions to another..." EPA proposes to amend Subparts X and Y to provide two

options for “molar volume conversion” factors that can be used by reporters for standard conditions of 60 F and 14.7 psia or 68 F and 14.7 psia.

No revisions are proposed for Subpart C, which currently defines standard conditions as 68 F and 14.7 psia, while the default natural gas heating value in Table C-1 is based on 60 F and 14.7 psia. The issue is further complicated in the proposed Subpart W, which introduces other, different “standard conditions” for gaseous sources. This inconsistency is extremely confusing and could lead to erroneous emission calculations. In addition, it places an unnecessary burden on reporters.

GPA requests that EPA consistently provide flexibility in using standard conditions of 60 F and 14.7 psia or 68 F and 14.7 psia in all parts of the GHG RP.

Response: We have concluded that the commenters’ request to use standard conditions of 60 °F and 14.7 psia or 68 °F and 14.7 psia is reasonable, and we are revising the definition of the term “MVC (molar volume conversion)” in the nomenclature of Equation C-5 of subpart C. The revised definition of MVC allows sources to use a MVC value of either 849.5 scf/kg mole (for a standard temperature of 68 °F) or 836.6 scf/kg mole (for a standard temperature of 60 °F).

Commenter Name: Michael Hannan
Commenter Affiliation: Williams Olefins LLC
Document Control Number: EPA-HQ-OAR-2008-0508-2357.1
Comment Excerpt Number: 30

Comment: Revise §98.34(a)(6) to remove the limitation of using a gas chromatograph for only gaseous fuels. This would make this Tier 2 fuel sampling and analysis requirement consistent with the Tier 3 requirement at §98.34(b)(4), which does not limit the use of a gas chromatograph to gaseous fuels.

Response: We agree with the commenter and have amended 40 CFR 98.34(a)(6) so as not to limit the use of gas chromatographs to gaseous fuels.

Commenter Name: Michael Hannan
Commenter Affiliation: Williams Olefins LLC
Document Control Number: EPA-HQ-OAR-2008-0508-2357.1
Comment Excerpt Number: 31

Comment: The Tier 3 calculation methodology QA/QC requirements at §98.34(b)(1) state that the requirements only apply to oil and gas flow meters but they should apply to all fuel flow meters.

§98.34(b)(1) You must calibrate each oil and gas fuel flow meter according to §98.3(i) and the provisions of this paragraph (b)(1).

Response: EPA is not making the recommended change. The reference to oil and gas fuel flow meters is sufficient to capture liquid and gaseous fuels reporting under the Tier 3 option. In addition, Equations C-4 and C-5 specify that fuel consumption must be provided by fuel flow meters calibrated according to 40 CFR 98.3(i) unless the fuel consumption is measured either by qualified fuel billing meters under 40 CFR 98.34(b)(3) or by oil tank drop measurements.

Commenter Name: Michael Hannan

Commenter Affiliation: Williams Olefins LLC

Document Control Number: EPA-HQ-OAR-2008-0508

.1

Comment Excerpt Number: 32

Comment: Revise §98.34(b)(1)(i)(C) to remove the term “industry-accepted” as it has the same meaning as the term “industry consensus standard” and is therefore redundant in the sentence.

§98.34(b)(1)(i)(C) You may use an industry-accepted or industry consensus standard calibration practice.

Response: To avoid confusion, we have revised 40 CFR 98.34(b)(1)(i)(C) to remove “industry consensus standard calibration” and only refer to “industry-accepted practice” Please see response to -: EPA-HQ-OAR-2008-0508-2396.1, excerpt 3

Commenter Name: Michael Hannan

Commenter Affiliation: Williams Olefins LLC

Document Control Number: EPA-HQ-OAR-2008-0508-2357.1

Comment Excerpt Number: 33

Comment: Revise §98.34(b)(1)(ii) to allow a consensus-based standards organization method to be used for recalibrating fuel flow meters. The Tier 3 calibration procedures at §98.34(b)(1)(i)(A) through (C) allow the initial fuel flow meter calibration to be performed according to one of three procedures: a method published by a consensus-based standards organization, a procedure specified by the meter manufacturer, or an industry consensus standard calibration practice. The recalibration procedures should allow the use of the same procedures.

§98.34(b)(1)(ii) In addition to the initial calibration required by §98.3(i), recalibrate each fuel flow meter (except as otherwise provided in paragraph (b)(1)(ii) of this section) either annually, at the minimum frequency specified by the manufacturer, at the interval specified by the consensus-based standards organization method, or at the interval specified by the industry consensus standard practice.

Response Recalibrations may be performed by using any procedure allowed for the initial calibration. We have amended 40 CFR 98.34(b)(1)(ii) to clarify that the frequency at which calibrations must be performed is according to one of the following. Recalibrations may be performed annually, at the minimum frequency specified by the manufacturer, or according to industry standard practice.

Commenter Name: Michael Hannan

Commenter Affiliation: Williams Olefins LLC

Document Control Number: EPA-HQ-OAR-2008-0508-2357.1

Comment Excerpt Number: 34

Comment: Revise §98.34(b)(1)(iii) to correct the recordkeeping citation.

§98.34(b)(1)(iii) Fuel billing meters are exempted from the initial and ongoing calibration requirements of this paragraph and from the Monitoring Plan and recordkeeping requirements of §98.3(g)(5)(i)(C), (g)(6) and (g)(7), provided that the fuel supplier and the unit combusting the fuel do not have any common owners and are not owned by subsidiaries or affiliates of the same company.

Response: We We agree with the commenter. The requirement in paragraph (g)(6) for Part 98 facilities to keep records of certification and QA test results is not appropriate for fuel billing meters. The QA/QC of these meters is the responsibility of the billing companies, and these companies are not regulated under Part 98. The final rule therefore adds paragraph (g)(6) of §98.3 to the list of monitoring plan record keeping requirements from which fuel billing meters are exempted.

Commenter Name: Michael Hannan

Commenter Affiliation: Williams Olefins LLC

Document Control Number: EPA-HQ-OAR-2008-0508-2357.1

Comment Excerpt Number: 35

Comment: It appears that 98.34(b)(4) has been revised. EPA may have inadvertently removed some important installation requirements for Tier 3 fuel meters in the original §98.34(b)(4) . For example, some of the methods previously listed contained requirements relative to the number of upstream and downstream distances from the nearest flow disturbance in order to assure accurate data. It is suggested to reinstate this paragraph but without the reference to specific methods, analogous changes to the fuel sampling paragraph, to provide more flexibility. This would require renumbering the EPA's proposed paragraph (b)(4) to (b)(5).

§98.34(b)(4) Install, operate, and maintain all fuel flow meters according to one of the following methods. You may use the manufacturer's recommended procedures, a method published by a consensus-based standards organization, or industry consensus standard practice. Consensus-based standards organizations include, but are not limited to, the following: ASTM International, the American National Standards Institute (ANSI), the American Gas Association

Response: We do not agree with the commenter's assessment. The final rule provides a great deal of flexibility in choosing an appropriate calibration method. It is true that some of the methods in the list that was removed from the rule do have specific installation requirements (e.g., AGA Report No. 3 for orifice plates). But since these installation requirements are method-specific, no universally applicable installation requirements were lost by removing the list of methods from the rule. Regardless of which calibration method is selected, if the method includes special installation requirements, the source will have to meet those requirements in addition to performing the calibration procedures.

Commenter Name: David A. Buff

Commenter Affiliation: Golder Associates Inc.

Document Control Number: EPA-HQ-OAR-2008-0508-2395.1

Comment Excerpt Number: 1

Comment: The proposed 98.34(a)(2)(ii)(B) adequately addresses situations where multiple fuel deliveries are obtained from one supplier during a month. However, during the course of a month, or even daily, a facility may receive multiple fuel shipments from different supply sources, even though the shipments are from the same fuel oil distributor. This revision would still require sampling multiple fuel oil deliveries in a given day or month if fuel oil is received from different supply sources. This provision should be revised to require only quarterly sampling for stationary combustion sources that fire a limited amount of fuel oil on an annual basis (i.e. <10% annual capacity factor) regardless of the number of fuel oil suppliers (or the number of "lots"). Language similar to that in 98.34(a)(2)(iii) would be appropriate. It would also be appropriate to allow a composite sample to be obtained over the quarterly period to reduce the analytical burden. Another option for these type sources would be to allow for the use of default HHV values.

Response: For a discussion on what is considered a fuel lot, see EPA's response to comment EPA-HQ-OAR-2008-0508-2381, Excerpt 1. Also see EPA's response to comment EPA-HQ-OAR-2008-0508-2381, Excerpt 2 on sampling from in-service fuel oil tanks. EPA has concluded that our interpretation of "supply source" in Section II.G of the Preamble, combined with the rule provisions for sampling in-service tanks only will sufficiently reduce the burden on units operating with low capacity factors. Use of a default HHV is not appropriate where a unit is larger than 250 mmBtu/hr.

Commenter Name: Walter Tyler

Commenter Affiliation: INVISTA

Document Control Number: EPA-HQ-OAR-2008-0508-2372.1

Comment Excerpt Number: 1

Comment: EPA is proposing to revise 40 CFR 98.33(a)(2)(iii) [Footnote: It appears that the reference to 40 CFR 98.33(a)(2)(iii) should actually be 40 CFR 98.34(a)(2)(iii).] by replacing “fossil fuel-derived gaseous fuels” with “other fuels (gaseous)” and additional related changes. INVISTA’s facilities have multiple units that burn process waste off gases that currently are not identified as fuels in Subpart C. With the proposed language change to this subpart, and the other language changes proposed, there is significant potential for confusion about the applicability of Subpart C requirements to the process waste off gases burned in these types of units.

To provide additional context, the definitions of Fuel Gas and Fuel Gas System at 40 CFR 98.6 currently describe processes at petroleum refineries and petrochemical plants that collect gaseous fuels for combustion. The definition of Fuel Gas System describes gas handling (e.g., compression, knock-out pots, etc.) and processing (e.g., sulfur removal) that usually are associated with the extraction of fuel gases from production units at petroleum refineries and petrochemical plants. These gaseous fuels from refinery and petrochemical processes tend to be similar to the hydrocarbons found in natural gas. The broad-based language of “other fuels (gaseous)” could be interpreted to apply to process waste off-gases from any chemical production unit at facilities that are not petroleum refineries or petrochemical plants and that do not have characteristics and properties similar to natural gas. The inclusion of these chemical processes in this definition does not appear to meet the intent of the regulation. To avoid this potential unintended consequence EPA should modify the definition of “Fuel” in 40 CFR 98.6 as follows “Fuel means solid, liquid or gaseous combustible material, but excludes process waste off gases from chemical production plants that are not petroleum refineries or petrochemical plants.”

Response: We did not intend to impose Tier 3 requirements on units that would not have otherwise been subject to Tier 3 prior to the proposed change. We have addressed this concern in the final rule by modifying the definition of “fuel gas” to include only fuels generated at petroleum refineries or petrochemical processes subject to subpart X of the rule. Please see Section II.G of the preamble for a further discussion for a rationale for the change in definition of fuel gas.

Commenter Name: Gregory J. Wooten

Commenter Affiliation: American Electric Power (AEP)

Document Control Number: EPA-HQ-OAR-2008-0508-2381

Comment Excerpt Number: 1

Comment: AEP is requesting that EPA further clarify fuel oil HHV sampling requirements. Under the proposed amendments, EPA is proposing to more precisely define the term “fuel lot” as it pertains to facilities that receive multiple deliveries of a particular fuel from the same supply source each month, either by truck, rail, or pipeline. The proposed amendment clarifies that a fuel lot consists of all of the deliveries for a given calendar month. Thus, for these facilities, the required HHV sampling frequency would be no greater than once per month. From the end users standpoint (AEP), we are interpreting the term “supply source” as it applies to distillate oil

grades to mean a single vendor. For example, AEP may place an order for No. 2 distillate fuel oil from a vendor who chooses to deliver the fuel oil to the AEP facility over a number of days in several truck loads. AEP interprets the proposed amendment to allow the facility to obtain one sample and analysis for HHV per month for the No. 2 distillate fuel oil from a specific vendor. If the facility also takes delivery of a different fuel type (e.g. No. 1 distillate fuel oil), then one sample per month from the vendor for that fuel type would also be obtained and analyzed. AEP would appreciate EPA confirming that this interpretation is acceptable and consistent with the amendment.

Response: For fuel oil, as noted in Section II.G of the Preamble, the “supply source” may be a particular refinery, bulk terminal, or fuel oil distributor, provided the fuel properties can reasonably be expected to be consistent. For a specific grade number of fuel oil, EPA expects there to be little variation for the HHV and one sample per month for each grade of fuel delivered from each supply source is acceptable. The owner or operator must document in the monitoring plan how the monthly sampling for each fuel type in Table C-1 is performed.

Commenter Name: David A. Buff
Commenter Affiliation: Golder Associates Inc.
Document Control Number: EPA-HQ-OAR-2008-0508-2395.1
Comment Excerpt Number: 2

Comment: If a facility has already implemented a fuel sampling plan required by a Title V operating permit, this sampling plan should be used in lieu of the requirements of 98.34. This would significantly reduce the sampling and monitoring burden on a facility that may be required to sample, analyze, and report fuel characteristics on a different schedule than those required by the mandatory reporting rule.

Response: For the purpose of obtaining consistent and verifiable data, we are not allowing exceptions to the fuel sampling frequencies specified in this rule. We note that the commenter did not provide examples of typical fuel sampling schedules that may be found in Title V permits. However, if the fuel sampling schedule in a Title V permit requires sampling at a frequency that is equal to or higher than the minimum frequency specified in Part 98, meeting that schedule would satisfy the requirements of the GHGRP.

Commenter Name: Walter Tyler
Commenter Affiliation: INVISTA
Document Control Number: EPA-HQ-OAR-2008-0508-2372.1
Comment Excerpt Number: 2

Comment: The text at 40 CFR 98.34(b)(3)(ii)(E) currently reads...”For gaseous fuels other than natural gas and biogas (e.g., process gas),...” The use of the term “process gas” appears to change the meaning of the “other fuels (gaseous)” phrase. INVISTA recommends 98.34(b)(3)(ii)(E) be modified to read...”For gaseous fuels other than natural gas and biogas

(e.g., fuel gas [not process gas]),...”

Response: The term “other fuels (gaseous)” in Table C-1 is meant to organize fuels by category, only. The fuels listed in Table C-1 under “other fuels (gaseous)” are not inclusive of all gaseous fuels other than natural gas and biogas. If a gaseous fuel is not listed in Table C-1, it would still be subject to the requirements of 40 CFR 98.34(b)(3)(ii)(E) if the use of Tier 3 is required. The reference to “process gas” in 40 CFR 98.34(b)(3)(ii)(E) does not change the meaning of the categorical heading of “other fuels (gaseous).” Process gas is not included in Table C-1, but it may still be subject to the requirements of 40 CFR 98.34(b)(3)(ii)(E). As such, EPA is not making any changes in response to this comment.

Commenter Name: Gregory J. Wooten

Commenter Affiliation: American Electric Power (AEP)

Document Control Number: EPA-HQ-OAR-2008-0508-2381

Comment Excerpt Number: 2

Comment: Regarding the proposed amendment that will allow manual oil samples to be taken after each addition of oil to the storage tank. AEP operates a number of distillate-oil fired auxiliary sources that operate infrequently and are subject to the HHV sampling requirements of the GHG reporting rule. As previously described, the fuel deliveries for the tanks that supply these sources at our facilities may arrive at the facility by truck over a number of days. It’s not unusual to receive delivery of several truck loads of fuel oil between periods of operation of the source. AEP believes that it would be appropriate to manually sample the fuel from the tank each day that the source is operated and that this method would be equivalent to the amendment that allows for sampling the tank after each addition of oil. AEP would appreciate EPA confirming that this interpretation is acceptable and consistent with the amendment.

Response: EPA agrees with the commenter and believes it is only appropriate to require fuel sampling of each addition to the storage tank when the tank is in service. However, the August 11, 2010 proposed rule did not provide such flexibility. As a result, we have amended §98.34(a)(2)(ii) to only require fuel sampling once the storage tank is placed in service and to only require sampling of each fuel addition as long as the tank remains in service. The final rule also clarifies that the daily manual sampling option requires sampling only on days when oil from the storage tank is combusted in the unit. Please see section II.G of the preamble to the final rule amendments for further information.

Commenter Name: Lisa Beal

Commenter Affiliation: Interstate Natural Gas Association of America (INGAA)

Document Control Number: EPA-HQ-OAR-2008-0508-2396.1

Comment Excerpt Number: 2

Comment: The Interstate Natural Gas Association of America (INGAA) approves of several revisions in the Proposed Rule regarding methodologies and practices that are acceptable. For example, to determine heating value, §98.34(a)(6) is revised to indicate that, “You may use a

method published by a consensus standards organization if such a method exists, or you may use industry consensus standard practice to determine the high heat values.” This general reference to consensus methods is preferable to the original rule requirements, which provided a long list of specific allowable methods. INGAA approves of this change. In addition, the Proposed Rule references “industry standard practices” for procedures such as flow meter calibration, and INGAA agrees that industry standard practices should be acceptable for addressing reporting rule requirements.

Response: EPA thanks the commenter for the input. We have finalized the amendments noted by the commenter as proposed.

Commenter Name: Ted Michaels

Commenter Affiliation: Energy Recovery Council (ERC)

Document Control Number: EPA-HQ-OAR-2008-0508-2393.1

Comment Excerpt Number: 3

Comment: EPA’s Clarifications to Tier 4 Monitoring Requirements. The Energy Recovery Council (ERC) supports EPA’s proposal to clarify CEMS hourly average data validation consistent with 40 CFR 60.13. This will ensure CO₂ validation is consistent with CEMs for SO₂, NO_x and CO required for Part 60 sources such as large MWCs. We note, however, that EPA has proposed a recommendation for quarterly ASTM 7459-08 sampling (collect small amount 1-5 cc every hour for quarter). In practice this recommendation would be very difficult and costly to implement as it would require separate sample collection system and could not be readily integrated into an existing CEM system without considerable modifications to sampling components and software. Because of the significant impediments to implementing quarterly ASTM 7459-08 sampling, we strongly recommend that EPA delete this proposed recommendation.

We do have a recommendation for refining the sampling requirement language to better facilitate the Agency’s recommendation that sampling be collected over a longer time period, EPA should revise the sampling requirement by striking out the word “consecutive” to: “... collect gas sample during normal operation for at least 24 [consecutive] hours or for as long as is deemed necessary to obtain a representative sample.” Eliminating the term “consecutive” would allow a source to spread sampling out over longer period of time consistent with EPA’s own recommendation.

Response: The final rule removes the word “consecutive” from the rule text in 98.34(d). Therefore, collection of the quarterly gas samples over 24 cumulative hours is acceptable. We have also clarified that the “recommendation” to withdraw a small 1-5 cc sample during every operating hour is only an option. The biogenic percentage of the total CO₂ emissions from MSW combustion varies not only with the composition of the MSW, but also with the amount of fossil fuel (if any) co-fired with the MSW. By installing a continuous sampling device, any changes in MSW properties or fuel blend ratios would be captured.

Our intent in recommending the use of a continuous sampling device was to suggest a way to eliminate these uncertainties in quantifying biogenic CO₂ emissions from MSW. However, the proposed rule did not include guidelines for determining when continuous sampling is required. Therefore, the final rule simply states that sources are free to consider using a continuous sampling device in situations where the blend ratio or type of MSW combusted is not consistent ---but this is not a requirement.

Commenter Name: Pamela A. Lacey

Commenter Affiliation: American Gas Association

Document Control Number: EPA-HQ-OAR-2008-0508-2394.1

Comment Excerpt Number: 4

Comment: The American Gas Association (AGA) supports the proposal to remove the lists of specific standards in section 98.34(a)(6), (b)(4) and (b)(5) and to replace the lists with a statement that reporters “may use a method published by a consensus standards organization if such a method exists, or you may use industry standard practices to determine” high heat values and carbon content of fuel. We agree this approach avoids the potential for omitting important standards, as occurred in section 98.7. We appreciate your inclusion of AGA in the statement that “Consensus-based standards organizations include, but are not limited to, the following: ... the American Gas Association (AGA).”

Response: EPA thanks the commenter for the input. Generally, we have finalized the amendments noted by the commenter as proposed. The final rule provides contact information for the listed organizations.

Commenter Name: Eldon Lindt

Commenter Affiliation: Xcel Energy Inc.

Document Control Number: EPA-HQ-OAR-2008-0508-2374.1

Comment Excerpt Number: 4

Comment: Currently, under the final rule, sampling from each fuel lot is required for Tier 2 units burning coal and fuel oil. The proposed rule clarifies the fuel lot definition for coal and fuel oil to be a shipment or delivery of a single fuel (e.g., ship load, barge load, group of trucks, oil delivery via pipeline from a tank farm, group of railroad cars, etc.). Therefore, when multiple deliveries of a particular type of fuel are received from the same supply source in a given calendar month, the deliveries for that month are considered, collectively, to comprise a fuel lot. This broader definition of a fuel lot reduces sampling burden for facilities with frequent fuel deliveries. At the most, sampling from the same supply source will be required once per month. Xcel Energy supports this expanded definition of a fuel lot because it reduces the sampling burden, but does not affect the accuracy of the emissions report.

Response: EPA thanks the commenter for the input. For additional information on EPA’s final amendments clarifying the definition of “fuel lot” please refer to Section II.G of the preamble.

Commenter Name: Lisa Beal

Commenter Affiliation: Interstate Natural Gas Association of America (INGAA)

Document Control Number: EPA-HQ-OAR-2008-0508-2396.1

Comment Excerpt Number: 5

Comment: For natural gas systems, frequent HHV analysis will often be available in association with existing gas chromatographs that monitor gas quality. For Subpart C, §98.34(a)(4) requires that “all valid fuel analyses” be used in GHG emission calculations. In some cases, existing operational practices include regular sampling (e.g., multiple sample in a day or hour) using gas chromatography (GC) to determine gas properties, including HHV. Thus, the rule essentially penalizes operators for having plentiful data by requiring implementation of new “data handling” procedures for HHV averaging and for addressing missing data.

Existing GC instruments and operating procedures follow standard operating practices and the associated accuracy meets the accuracy objectives for GHG reporting. To avoid confusion and unnecessary burden regarding criteria for natural gas HHV sampling, the requirements for natural gas analysis should be clarified. Current practices should be accepted to avoid the need to develop new computer algorithms that specifically follow Subpart C calculation methodology. Averaging or reporting data at high frequency should not be required and Part 98 missing data algorithms should not be required because this added burden is not warranted.

The Interstate Natural Gas Association of America (INGAA) recommends that operators be allowed to use existing averaging procedures. In addition, many sites have gas quality that does not vary significantly. In those cases, a single monthly natural gas analysis result provides an accurate means to estimate emissions and a single analysis from within the month should be allowed to determine HHV for natural gas. The methods and data averaging used can be identified in the GHG Monitoring Plan.

To address this, §98.34(a)(4) should be revised, and INGAA recommends the following (see the edits in square brackets):

“(4) If, for a particular type of fuel, HHV sampling and analysis is performed more often than the minimum frequency specified in paragraph (a)(2) of this section, the results of all valid fuel analyses shall be used in the GHG emission calculations. [For natural gas-fired sources with multiple HHV samples and analyses within a single month, operator procedures or a single analysis from the month can be used to determine HHV. The procedure used to determine HHV shall be identified in the GHG Monitoring Plan required in §98.3(g)(5). For natural gas-fired sources, operator procedures can include alternative missing data procedures to those specified in §98.35.]”

Response: See the response to comment EPA-HQ-OAR-2008-0508-2383.1, Excerpt 39.

Commenter Name: Joel R. Hall
Commenter Affiliation: Mexichem Fluor Inc.
Document Control Number: EPA-HQ-OAR-2008-0508-2365
Comment Excerpt Number: 5

Comment: Mexichem supports the EPA's proposal to remove the list of specific methods for determining HHV and carbon content and for fuel flow meter calibration, and specify instead that sources must either use appropriate methods from consensus standards organizations if such methods exist, or standard industry practice.

Response: EPA thanks the commenter for the input. We have finalized the amendments noted by the commenter as proposed.

Commenter Name: Caitlin Post
Commenter Affiliation: Southern Company
Document Control Number: EPA-HQ-OAR-2008-0508-2377.1
Comment Excerpt Number: 5

Comment: EPA is proposing to clarify the frequency at which the high heating value (HHV) needs to be determined for various fuel types. Southern Company supports EPA's clarification of CFR 98.34(a)(2)(ii) that allows multiple deliveries of a particular fuel from the same supply source in a calendar month to be considered a "fuel lot" and only require one representative sample. This clarification is appropriate because it eliminates the burden of sampling each truck delivery (there could be multiple deliveries a day) from the same source.

Southern Company believes it is the intent of EPA to capture the HHV of the fuel oil that is actually being combusted. This intent is supported by the proposed option to sample fuel oil each time fuel oil is added to a unit's storage tank instead of by fuel lot. Southern Company supports this option; however, this proposal does not provide needed clarification for facilities with multiple storage tanks. For example, a Southern Company facility has three storage tanks. Currently, Tank #1 is in service supplying fuel oil to the generating units. Tank #2 is designated as filling and is receiving shipments of fuel oil. (Tank #3 is maintained empty.) Tank #2 will not be placed into service until the in service tank (Tank #1) is depleted. Due to low run hours and the large capacity of the fuel storage tanks, the facility may not have a need to swap from Tank #1 to Tank #2 for a number of years. Because no fuel is moved from Tank #2 to Tank #1, the fuel sampling as currently required by the MRR is not capturing the HHV for the fuel oil that is actually being combusted. The MRR requires sampling of fuel as it is delivered or, as now proposed, when the fuel is added to a storage tank. These conditions require this facility to use the HHV of fuel that has not been combusted to calculate the greenhouse gas emissions from the unit for the current year (because the fuel that is being delivered and put into storage tanks is being added to Tank #2, not the in service Tank #1). Southern Company believes EPA does not intend for facilities to report emissions based on fuel that has not been used. To address this issue, Southern Company suggests that EPA allow facilities with multiple storage tanks to sample the fuel oil from the in-service tank twice a year and before a tank is placed into service.

Response: See the response to comment EPA-HQ-OAR-2008-0508-2381, Excerpt 2, for the response on sampling in-service tanks only.

Commenter Name: Eldon Lindt

Commenter Affiliation: Xcel Energy Inc.

Document Control Number: EPA-HQ-OAR-2008-0508-2374.1

Comment Excerpt Number: 5

Comment: Under the proposed rule, as an alternative to sampling with every fuel lot, Tier 2 units burning fuel oil can perform sampling after each addition to the storage tank using manual sampling methods, flow-proportional sampling, and continuous drip sampling. Xcel Energy supports giving reporters this alternative because it draws on current industry practices and reduces sampling burden at a number of our facilities.

Response: EPA thanks the commenter for the input. For additional information on EPA's final amendments clarifying the definition of "fuel lot" please refer to Section II.G of the preamble.

Commenter Name: Eldon Lindt

Commenter Affiliation: Xcel Energy Inc.

Document Control Number: EPA-HQ-OAR-2008-0508-2374.1

Comment Excerpt Number: 8

Comment: The proposed rule clarifies that facilities combusting MSW as either the primary or only fuel, paragraph (d), and facilities combusting combinations of biomass fuels, paragraph (e), shall perform a quarterly biomass (biogenic) CO₂ analysis. Furthermore, the samples have to be collected for at least 24 consecutive hours. Xcel Energy believes this is excessive and that a shorter sample duration will give representative results. The supporting information is organized into three sections: facility descriptions, a discussion of MSW versus RDF, and 2010 biogenic CO~ sampling results.

Response: The final rule allows sources to perform a demonstration, comparing the results of 8-hour and 24-hour samples, to justify reducing the required minimum sampling time to 8 hours. Please see Section II.G of the preamble for further discussion.

Commenter Name: Eldon Lindt

Commenter Affiliation: Xcel Energy Inc.

Document Control Number: EPA-HQ-OAR-2008-0508-2374.1

Comment Excerpt Number: 9

Comment: The Red Wing Plant is an electric power generating station located along the Mississippi River in Red Wing, Minnesota. The Red Wing plant is rated at 25 megawatts (MW) and has two boilers that burn RDF. The RDF burned at this facility is processed under contract with the Elk River Resource Recover Facility in Elk River, Minnesota, and the Ramsey/Washington Resource Recovery Facility in Newport, Minnesota. The RDF is brought onsite via truck and unloaded in the receiving area. From there, a single conveyor brings the fuel into the plant where it is then directed into either of the two traveling grate boilers.

The Wilmarth facility is an electric power generating station located along the Minnesota River in Mankato, Minnesota. The Wihmarth plant is rated at 25 MW and has two boilers that burn RDF. The RDF burned at this facility is processed under contract with the Elk River Resource Recover Facility in Elk River, Minnesota, and the Ramsey/Washington Resource Recovery Facility in Newport, Minnesota. The RDF is brought onsite via truck and unloaded in the receiving area. From there, a single conveyor brings the fuel into the plant where it is then directed into either of the two traveling grate boilers.

The French Island facility is an electric power generating station located along the Mississippi River in La Crosse, Wisconsin. During normal operation, the two boilers at the French Island plant burn a mixture of 50% RDF and 50% wood (ground treated railroad ties), each rated at 15 MW. The current air quality permit allows no more than 50% RDF in the mixture. MSW is brought onsite and processed to RDF before combusted in the boilers. Ground treated railroad ties are brought onsite via truck. The railroad ties are mixed with the RDF before being directed into either of the two boilers.

MSW versus RDF:

By definition, RDF and MSW are different. RDF is processed MSW that goes through various stages to remove all non-combustibles such as glass and metals, and larger objects such as mattresses and carpet. Please note that the processing facilities are not allowed to accept industrial solid wastes and hazardous materials with the MSW. Once sorted, the combustible waste is shredded and dried before shipping to the facilities as RDF. The composition of RDF is much more homogenous than unprocessed MSW and, as a result, emissions from combustion of RDF are much less variable than emissions from MSW. Therefore, it is reasonable to have different biogenic sampling requirements for RDF and MSW facilities.

2010 biogenic CO₂ sampling results:

Starting January 1, 2010, quarterly samples have been collected at each of the qualifying facilities listed above. For the benefit of this research, multiple units were sampled at each facility, even though the rule only requires sampling at one unit per facility because of the common fuel source. Sample times ranged from 1-hour to 24-hours. Beta Analytic Inc. out of Miami, Florida, performed the biogenic CO₂ analysis per ASTM D6866-08 (Standard Test Methods for Determining the Biobased Content of Solid, Liquid, and Gaseous Samples Using Radiocarbon Analysis). The test results are practically identical regardless of the collection duration time, and are all within ~: 3% of the mean average of 60% for the two facilities. The French Island facility's biogenic CO₂ content is slightly higher due to the fact they burn a 50/50 mixture of RDF and wood. Nonetheless, the results from a 24-hour sample are within 1% of the results seen from a 4-hour sample taken that same day on the same unit.

Facilities that combust RDF, or a combination of RDF and biomass (such as wood), should be exempt from the 24-hour minimum sample duration due to the fact that the fuel is processed and is less variable than MSW. For RDF and RDF combinations, we suggest a minimum sample duration of 8 hours, not only because it will still capture a representative sample, but also because sampling is labor intensive and requires an employee onsite for the entire data collection period. See DCN:EPA-HQ-OAR-2008-0508-2374 for a table displaying the Sample Duration of Biomass from the facilities stated above.

Response: See the response to comment EPA-HQ-OAR-2008-0508-2374.1, Excerpt 8.

Commenter Name: Stephen E. Woock

Commenter Affiliation: Weyerhaeuser Company

Document Control Number: EPA-HQ-OAR-2008-0508-2375.1

Comment Excerpt Number: 9

Comment: §98.34(a)(2)(ii): This proposed revision allows multiple fuel deliveries from the same supplier during the same month to be considered a fuel lot for the purposes of fuel sampling. This revision accounts for the fact that fuel properties from the same supplier do not significantly change over short periods of time, e.g. weekly or daily. This is especially true if the supplier is drawing the fuel from large storage tanks, e.g. fuel oil, to supply its many customers. This revision also acknowledges the fact that fuel properties do not typically change from the same supplier because fuel specifications contracts are often in place with the buyers that limit the variability of the fuel properties. Weyerhaeuser supports this revision.

Response: EPA thanks the commenter for the input. For additional information on EPA's final amendments clarifying the definition of "fuel lot" please refer to Section II.G of the preamble.

Commenter Name: Stephen E. Woock

Commenter Affiliation: Weyerhaeuser Company

Document Control Number: EPA-HQ-OAR-2008-0508-2375.1

Comment Excerpt Number: 10

Comment: §98.34(b)(1)(i): This proposed revision removes the restrictive list of approved fuel flow meter calibration methods, and allows the use of either an appropriate published flow meter calibration method by a consensus standard organization, calibration procedures specified by the flow meter manufacturer, or an industry-accepted or industry consensus standard calibration practice. The use of consensus standard methods, industry standards or manufacture's specifications rather than an inflexible list of prescribed calibration methods afford the facility the alternative to select the most appropriate and accurate calibration method for their particular measurement device. Due to the variety of flow measurement devices, this flexibility ensures the

proper alignment between the measurement device with the appropriate calibration methodology. Weyerhaeuser supports this revision.

Response: EPA thanks the commenter for the input. We have finalized the amendments noted by the commenter as proposed.

Commenter Name: Kerry Kelly
Commenter Affiliation: Waste Management (WM)
Document Control Number: EPA-HQ-OAR-2008-0508-2400.1
Comment Excerpt Number: 1

Comment: EPA's Clarifications to Tier 4 Monitoring Requirements
ERC supports EPA's proposal to clarify continuous emissions monitoring (CEMs) hourly average data validation consistent with 40 CFR 60.13. This clarification will ensure CO₂ validation is consistent with required CEMs for criteria pollutants (SO₂, NO_x and CO) applied to Part 60 sources such as large MWCs. We note, however, that EPA has proposed a recommendation for quarterly ASTM 7459-08 sampling ("collect small amount 1-5 cc every hour for quarter"). In practice this recommendation would be very difficult and costly to implement. The proposal would require development of a separate sample collection system and could not be readily integrated into an existing CEM system without considerable modifications to both sampling components and software. Because of the significant impediments to implementing quarterly ASTM 7459-08 sampling, we strongly recommend that EPA delete this proposed recommendation.

We do have a recommendation for refining the sampling requirement language to better facilitate the Agency's recommendation that sampling be collected over a longer time period, EPA should revise the sampling requirement by striking out the word "consecutive" to: "... collect gas sample during normal operation for at least 24 consecutive hours or for as long as is deemed necessary to obtain a representative sample." Eliminating the term "consecutive" would allow a source to spread sampling out over longer period of time consistent with EPA's own recommendation.

Response: See the response to comment EPA-HQ-OAR-2008-0508-2393.1, Excerpt 3.

Commenter Name: Mark Strohfus
Commenter Affiliation: Great River Energy
Document Control Number: EPA-HQ-OAR-2008-0508-2391.1
Comment Excerpt Number: 1

Comment: RDF is a very homogenous fuel because of the level of mixing that occurs during its processing. The MSW is dumped from curbside collection trucks onto the receiving floor. A

front-end loader moves the trash around the floor into various working piles, which are later loaded into open feed troughs. Grapple crane operators watch the trash moving through the feed troughs and extract any larger materials such as furniture and carpeting that can upset the downstream processing operations. The acceptable trash then proceeds to multiple screening and shredding operations to remove ferrous metals, aluminum, sand, grit and glass. The final RDF product is a well mixed composite of materials that are approximately 2 inches by 6 inches in size or smaller. The RDF is then trucked to Elk River Station, where it is once again dumped onto a receiving floor, pushed into a large feeder pile, and eventually loaded onto a walking floor feeder trough. Because of the significant mixing and processing done in the RDF production process, the RDF burned at 2:00 am is very similar in biogenic content as the fuel burned at 2:00 pm.

Collecting a sample over 24 hours is unnecessarily burdensome. Sampling for more than 8 hours requires one shift operator to transfer the sampling duties along with all the other daily duties to the next shift operator. Overnight shifts are staffed at lower levels making the additional duties more burdensome. Furthermore, professional staff can help with sampling duties during daytime shifts in the event that the operators need to tend to duties elsewhere in the plant.

During the most recent biogenic sampling, Great River Energy collected samples over varying timeframes to demonstrate that shorter sampling durations result in the same level of measured biogenic emission fractions. We collected, in accordance with ASTM D7459-08 sampling protocol: 1) a 24-hour composite sample by drawing a flue gas sample once every hour into a large sample bag (09/14 7:00 pm – 09/15 6:00 pm), 2) an 8-hour composite sample by drawing a flue gas sample once every hour (09/15 8:40 am – 4:40 pm), and 3) a 1-hour continuous sample (09/15 2:40 pm – 3:40 pm). The flue gas samples were analyzed by Beta Analytical, Miami, FL. Results are summarized in the following table [see table in EPA-HQ-OAR-2008-2391.1].

Beta Analytical cites its ASTM-D6866 test has an absolute precision of $\pm 3\%$, which means the results for all three sampling time frames are equal.

Samples collected and analyzed during the first and second quarter of 2010 are also equal. The biogenic portion was 61 percent and 59 percent during the first and second quarter, respectively, suggesting that there may not even be any seasonal variability in the biogenic fraction.

Great River Energy's results demonstrate that collecting a flue gas sample over a 24-hour period is not necessary to ensure that representative data is obtained. Clearly in the case of Elk River Station, a one-hour sample is as representative of the fuel's biogenic portion over a 24-hour sample and over the first three quarters of calendar year 2010. At a maximum, Great River Energy recommends the rule require quarterly sampling with no more than an 8-hour sample being collected for RDF-fired facilities. By limiting the sampling duration to eight hours or less, we can avoid the pitfalls of having to transfer sampling duties from one shift of operators to the next shift.

Response: See the response to comment EPA-HQ-OAR-2008-0508-2374.1, Excerpt 8.

Commenter Name: Lauren E. Freeman
Commenter Affiliation: Utility Air Regulatory Group (UARG)
Document Control Number: EPA-HQ-OAR-2008-0508-2388.1
Comment Excerpt Number: 10

Comment: VII. Fuel Sampling for Coal and Fuel Oil

As promulgated, the Tier 2 and 3 methodologies in §§ 98.34(a)(2)(ii) and (b)(3)(ii) require “for coal and fuel oil, analysis of at least one representative sample from each fuel lot,” which is defined as a shipment or delivery of a single fuel. In its Reconsideration Petition, UARG expressed concern that this requirement might not be satisfied by the Part 75, Appendix D sampling methods that rely on sampling from tanks or from fuel lines downstream of a tank (since those methods do not sample each lot or shipment). Although Part 75 sources are reporting CO₂ under Part 75, other combustion units at a facility that share a fuel supply with a Part 75 unit could be required to perform unnecessary and duplicative sampling and analysis if the Part 75 sampling did not satisfy Tier 2 or 3. UARG also is concerned that without further guidance regarding what constitutes a “fuel lot” when multiple deliveries are received of a particular fuel (e.g., multiple trucks or train cars), sources that are sampling deliveries may either sample too much or too little.

To address these concerns, EPA proposes to revise § 98.34(a)(2)(ii) and (b)(3)(ii) to make clear that fuel sampling options allowed or required under Part 75 (i.e., manual oil sampling from storage tanks after addition of oil, daily manual sampling, flow-proportional sampling, and continuous drip sampling) are allowed. 75 Fed. Reg. at 48,760. EPA also proposes to revise the rule to provide that multiple deliveries from the same supply source in a month would be considered a single lot. This revision would ensure that unless a supply source changed, sampling would not be required more than once a month. This revision is reasonable and necessary to ensure consistent implementation of the rule without an excessive amount of sampling.

Response: EPA thanks the commenter for the input. For additional information on EPA’s final amendments clarifying the definition of “fuel lot” please refer to Section II.G of the preamble.

Commenter Name: Lauren E. Freeman
Commenter Affiliation: Utility Air Regulatory Group (UARG)
Document Control Number: EPA-HQ-OAR-2008-0508-2388.1
Comment Excerpt Number: 11

Comment: VIII. Use of Consensus Standard Methods

As promulgated, §§ 98.34(a)(6), (b)(4), and (b)(5) list specific consensus standards that must be used for fuel sampling and analysis for HHV under Tier 2, fuel flow meter calibrations under Tier 3, and carbon content analysis under Tier 3, respectively. In its Reconsideration Petition, UARG objected to the Tier 2 sampling, analysis, and reporting requirements to the extent that Tier 2 requires sampling and/or analysis for HHV that is different than the sampling and analysis

already performed for that fuel under Part 75, Appendix D. UARG also is concerned that specifying particular methods, which are required by the Office of the Federal Register to be identified in the rule not only by method number but also by year of authorization or revision, sources might become subject to different methods for the same task under different rules. For example, although this rule lists a number of the same ASTM methods for sampling and analysis as Part 75, Appendix D, the cited methods are not from the same year. While the differences between the versions may sometimes be small, sources may have difficulty determining whether an analysis performed under one version is sufficient to satisfy the other. In other cases, the versions may be very different. No source should be required to apply two different methods to obtain the same data under different rules.

To address UARG's concerns, and concerns expressed by others, EPA proposes to revise §§ 98.34(a)(6), (b)(4) and (b)(5) to remove references to specific consensus standards and to instead allow use of any appropriate standard. 75 Fed. Reg. at 48,761. This revision is not only reasonable, it is necessary to ensure that sources are not subject to multiple different, but duplicative, methods under different rules. The revision also has the advantage of allowing sources to use improved methods without petitioning EPA for an exception to the rule or waiting for a rule revision.

CATF objects to EPA's removal of specific consensus standards from these provisions, arguing that this will lead to inconsistencies in accuracy between sources and frustrate EPA's verification of emissions. EPA-HQ-OGC-2010-0575-14 at 4-5. CATF's concerns are overblown. As promulgated the rule already allows use of a variety of methods. Allowing use of revised methods or newly developed methods does not change that fact. The alternative proposed by CATF -- requiring sources to perform "uncertainty assessments" for each method prior to use -- is not realistic. Few consensus standards provide this information and individual sources cannot be expected to perform the sort of research needed to develop such statistics for each method they use. The proposed revised rule is more than sufficient to satisfy its intended purpose, which is to provide Congress and EPA information to inform future legislative and regulatory decision.

Response: EPA thanks the commenter for the input. We concur with the commenter's response to CATF and have finalized the amendments noted by the commenter, as proposed. See section II.G of the preamble to the final rule amendments for further information.

Commenter Name: Craig Holt Segall

Commenter Affiliation: Sierra Club Environmental Law Program et. al

Document Control Number: EPA-HQ-OAR-2008-0508-2398.1

Comment Excerpt Number: 16

Comment: Finally, we are somewhat concerned with the effect of EPA's proposed amendment to the monitoring methods provided in section 98.33 for MSW facilities. EPA proposes to amend these methods by requiring facilities who combust MSW to calculate their methods using ASTM D-6866-08 and ASTM D7459-08 methodologies. We request that EPA in the final rulemaking ensure that these methodologies are as accurate as those contained currently in section

98.33(e)(3). If they are not, EPA should not adopt the proposal. In addition, EPA should once again take this opportunity to strengthen the provisions of this rule by requiring facilities that combust MSW to report the amount and type of MSW. Finally, EPA proposes to require testing at only one unit if MSW is the primary fuel at the facility and “the units are fed from a common fuel source.” We request that EPA clarify what is meant by “common fuel source” in the last sentence of proposed section 98.33(d). If the MSW fueling different units is fairly uniform, we do not see this proposal as problematic. However, if there is the potential that the constituents of the MSW fueling different units could vary, EPA should require testing at all units.

Response: Part 98 has always required use of ASTM methods D7459-08 and D6866-08 for determining biogenic CO₂ emissions from MSW combustion (see §98.34(d)). In fact, these are the only methods that we know of that are capable of providing this information for a partly biogenic fuel such as MSW. Results obtained from these methods are estimated to be accurate to within about 2 to 3%. EPA therefore finds no need to strengthen the provisions for calculating biogenic CO₂ emissions from MSW combustion.

We have not incorporated the commenter’s suggestion to define “common supply source”. Based on many years of experience with stationary combustion units, we do not expect to see significant variation in fuel composition when multiple units at the same facility combust the same type of fuel.

Commenter Name: Helen D. Silver
Commenter Affiliation: Clean Air Task Force et. al
Document Control Number: EPA-HQ-OAR-2008-0508-2403.2
Comment Excerpt Number: 7

Comment: We oppose EPA’s proposed weakening of the requirements for fuel lot sampling for coal and fuel oil, as proposed in the UARG settlement. See 75 Fed. Reg. at 48,760. Carbon dioxide emissions from coal vary based on the carbon, hydrogen, and oxygen content. These parameters can vary significantly among different sources of coal. By going from a representative sample of each shipment or delivery of a single fuel to one sample for an entire month’s worth of deliveries, EPA is creating a potentially significant loophole for underreporting or otherwise mis-calculating emissions.

Under EPA’s final rule, a fuel lot is defined straightforwardly as “a shipment or delivery of a single fuel (e.g., ship load, barge load, group of trucks, oil delivery via pipeline from a tank farm, group of railroad cars, etc.)” 40 C.F.R. § 98.34(a)(2)(ii). The proposed revision would introduce an alternative definition as follows: “[i]f multiple deliveries of a particular type of fuel are received from the same supply source in a given calendar month, the deliveries for that month are considered, collectively, to comprise a fuel lot, requiring only one representative sample.” 75 Fed. Reg. at 48,792. We generally oppose a change from the sample-per-delivery current definition to the proposed sample-per-month definition, due to the increased uncertainty and variability such a change introduces into the fuel portion of the emission calculations. However,

if EPA chooses to weaken its fuel lot provision as proposed, there are several specific problems with the change which EPA should address in its final rulemaking.

First, the definition of “supply source” is not clear. EPA should specify whether a supply source means a particular mine/well or a fuel supply company owning several mines/wells, or has some other meaning. We believe that the former definition should apply. Focusing on a mine or well as opposed to a fuel supply company likely will reduce the range of variability in fuel parameters seen in a month’s worth of deliveries, such that any single sample better captures the fuel actually received and combusted.

Second, and more importantly, the rule does not contain adequate provisions for determining whether, and ensuring that, a particular sample is representative of a month’s worth of deliveries. EPA should specifically delineate the standards and parameters by which the agency will gauge a fuel sample’s representativeness for the month. One could read the existing general recordkeeping requirements as extending to the fuel sample representativeness analysis. However, the recordkeeping provision only states that a source must retain “the data used to calculate the GHG emissions for each unit... [including]... (iii) The results of all required analyses for high heat value, carbon content, and other required fuel or feedstock parameters. (iv) Any facility operating data or process information used for the GHG emission calculations.” 40 C.F.R. § 98.3(g)(2). It contains no explicit requirements for determining fuel sample representativeness, but reads as a catchall provision incorporating substantive requirements from elsewhere in the regulations. Since there are no such substantive requirements for fuel representativeness in the fuel lot provision, the general recordkeeping provision is inadequate to provide any guidance to sources and the public that would ensure consistency in analysis across sources.

Response: See the response to comment EPA-HQ-OAR-2008-0508-2381, Excerpt 1.

Commenter Name: Craig Holt Segall

Commenter Affiliation: Sierra Club Environmental Law Program et. al

Document Control Number: EPA-HQ-OAR-2008-0508-2398.3

Comment Excerpt Number: 8

Comment: We oppose EPA’s proposed weakening of the requirements for fuel lot sampling for coal and fuel oil, as proposed in the UARG settlement. See 75 Fed. Reg. at 48,760. Carbon dioxide emissions from coal vary based on the carbon, hydrogen, and oxygen content. These parameters can vary significantly among different sources of coal. By going from a representative sample of each shipment or delivery of a single fuel to one sample for an entire month’s worth of deliveries, EPA is creating a potentially significant loophole for underreporting or otherwise mis-calculating emissions.

Under EPA’s final rule, a fuel lot is defined straightforwardly as “a shipment or delivery of a single fuel (e.g., ship load, barge load, group of trucks, oil delivery via pipeline from a tank farm,

group of railroad cars, etc.)” 40 C.F.R. § 98.34(a)(2)(ii). The proposed revision would introduce an alternative definition as follows: “[i]f multiple deliveries of a particular type of fuel are received from the same supply source in a given calendar month, the deliveries for that month are considered, collectively, to comprise a fuel lot, requiring only one representative sample.” 75 Fed. Reg. at 48,792. We generally oppose a change from the sample-per-delivery current definition to the proposed sample-per-month definition, due to the increased uncertainty and variability such a change introduces into the fuel portion of the emission calculations. However, if EPA chooses to weaken its fuel lot provision as proposed, there are several specific problems with the change which EPA should address in its final rulemaking.

First, the definition of “supply source” is not clear. EPA should specify whether a supply source means a particular mine/well or a fuel supply company owning several mines/wells, or has some other meaning. We believe that the former definition should apply. Focusing on a mine or well as opposed to a fuel supply company likely will reduce the range of variability in fuel parameters seen in a month’s worth of deliveries, such that any single sample better captures the fuel actually received and combusted.

Second, and more importantly, the rule does not contain adequate provisions for determining whether, and ensuring that, a particular sample is representative of a month’s worth of deliveries. EPA should specifically delineate the standards and parameters by which the agency will gauge a fuel sample’s representativeness for the month. One could read the existing general recordkeeping requirements as extending to the fuel sample representativeness analysis. However, the recordkeeping provision only states that a source must retain “the data used to calculate the GHG emissions for each unit... [including]... (iii) The results of all required analyses for high heat value, carbon content, and other required fuel or feedstock parameters. (iv) Any facility operating data or process information used for the GHG emission calculations.” 40 C.F.R. § 98.3(g)(2). It contains no explicit requirements for determining fuel sample representativeness, but reads as a catchall provision incorporating substantive requirements from elsewhere in the regulations. Since there are no such substantive requirements for fuel representativeness in the fuel lot provision, the general recordkeeping provision is inadequate to provide any guidance to sources and the public that would ensure consistency in analysis across sources.

Response: See the response to comment EPA-HQ-OAR-2008-0508-2381, Excerpt 1.

DATA REPORTING REQUIREMENTS

Commenter Name: Terry Mutter

Commenter Affiliation: Boeing Company

Document Control Number: EPA-HQ-OAR-2008-0508-2359.1

Comment Excerpt Number: 1

Comment: This rule should not require small combustion units to be individually inventoried or counted.

The proposed amendments to the rule provide a partial relief from data collection and reporting requirements of 40 CFR 98.36 (c)(1) and (c)(3). Specifically, the amendments remove the requirement for unique ID numbers to be assigned for each combustion unit at an affected source. The proposed amendment would allow sources to report only the total number of combustion units under an aggregated facility or pipeline. These are units without individual gas meters and for which generic Tier 1 emission calculations are appropriate.

The proposed change, while an improvement, does not remove the unwarranted burden to identify and inventory all combustion units, regardless of size. Without relief this will force facility personnel to annually perform a count of every furnace, process heater, water heater and lab burner at a site. At large, complex manufacturing facilities such as ours, the constantly changing inventory of combustion equipment assures the count will be inaccurate immediately after the annual accounting has been performed. Small furnaces and space heaters are continuously moved or installed as operations are changed, devaluing the data EPA is requesting.

The essence of the rule is to determine a facility's overall GHG output. Reporting the total number of all combustion units at a facility provides no additional value to the agency while significantly increasing the liability and burden on resources to the facility.

We ask that EPA either remove the individual combustion unit accounting requirement in 98.36 (c)(1) and (c)(3), or, establish a minimum threshold value to identify significant combustion units. A threshold value of 10 MMBTU/hr input and would be consistent with current Title V tracking and reporting requirements at most affected facilities.

Response: EPA agrees that keeping an accurate count of very small combustion sources can be burdensome. In view of this, we have withdrawn the proposed requirement to report the number of units in an aggregated group. We have concluded that the most essential information for the group is the heat input capacity of the largest unit. Therefore, we have removed and reserved §§98.36 (c)(1)(ii) and (c)(1)(iii). We have also removed and reserved §98.36(c)(3)(ii) under the common pipe reporting option, for similar reasons. See section II.G of the preamble to the final rule amendments for additional information.

Commenter Name: Michael Hannan

Commenter Affiliation: Williams Olefins LLC

Document Control Number: EPA-HQ-OAR-2008-0508-2357.1

Comment Excerpt Number: 36

Comment: Change the title of §98.36 from “Data reporting requirements” to “Data reporting and recordkeeping requirements” to more accurately reflect the contents of the section.

Response: No rule changes have been made as a result of this comment. The changes to Part 98 suggested by the commenter are outside the scope of the specific amendments proposed for public comment in the Federal Register notice of August 11, 2010. We note, however that although §98.36 does contain some record keeping provisions, changing the section title is unnecessary, as it is clear which data elements in §98.36 must be reported.

Commenter Name: Michael Hannan

Commenter Affiliation: Williams Olefins LLC

Document Control Number: EPA-HQ-OAR-2008-0508-2357.1

Comment Excerpt Number: 37

Comment: §98.36(c)(3) provides options available for estimating fuel use when two or more combustion units share a common fuel supply line or pipe. Most of the information in this paragraph describes emissions calculations and would therefore be more appropriately placed in §98.33. It is proposed to move the majority of §98.36(c)(3) to a new §98.33(f). Since this option is available for units using the new Tier 1 gas billing records option, as indicated in the second example provided by EPA, the language requiring measurement of the fuel should be revised to allow the fuel use to be obtained from billing records as well. An additional change is also proposed to account for a situation when a single combustion unit remains after other fuel users on the common supply line or pipe are accounted for in accordance with other applicable subparts. It is also appropriate to remove the term “in units of therms” consistent with changes suggested elsewhere in these comments. Suggested changes are as follows:

Keep the last sentence of §98.36(c)(3) with changes necessitated by moving most of the paragraph to new §98.33(f).

a.

§98.36(c)(3) When the common pipe calculation methodology described in §98.33(f) is used reporting option is selected, the following information shall be reported instead of the information in paragraph (b) of this section:

Move majority of §98.36(c)(3) to new §98.33(f) with changes shown below.

98.33(f) Common pipe configurations. 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, you 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, or, for natural gas, the amount of fuel combusted may be obtained from gas billing records. For Tier 3 applications, the flow meter shall be calibrated in accordance with §98.34(b). If a portion of the fuel measured, or obtained from gas billing records, at the common pipe is diverted to either: A flare, or another stationary fuel combustion unit (or units), including units that use a CO₂ mass emissions calculation method in part 75 of this chapter; or a chemical or industrial process (where it is used as a raw material but not combusted), and the remainder of the fuel is distributed to a group of combustion unit (or units) for which you elect to use the common pipe reporting option, you may

use company records to subtract out the diverted portion of the fuel from the fuel measured or obtained from gas billing records at the main supply line prior to performing the GHG emissions calculations for the group of unit(s) using the common pipe option. If the diverted portion of the fuel is combusted, the GHG emissions from the diverted portion shall be accounted for in accordance with the applicable provisions of this part. When 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, except where the applicable tier is based on criteria other than unit size. For example, if the maximum rated heat input capacity of the largest unit is greater than 250 mmBtu/hr, Tier 3 will apply, unless the fuel transported through the common pipe is natural gas or distillate oil, in which case Tier 2 may be used, in accordance with §98.33(b)(2)(ii). As a second example, in accordance with §98.33(b)(1)(v), Tier 1 may be used regardless of unit size when natural gas is transported through the common pipe, if the annual fuel consumption is obtained from gas billing records in units of therms.

Response: We do not agree that the commenter's suggested reorganization of §§98.33 and 98.36 is necessary. The common pipe option is not an alternative calculation method---it uses Tier 1, 2, or 3. Rather, it is an alternative reporting option, i.e., an alternative to single-unit reporting under §98.36(b). However, we have incorporated the commenter's suggestion to modify §98.36(c)(3) by including references to the use of gas billing records, when a portion of the fuel measured at the common pipe is diverted to a flare or combustion unit.

Commenter Name: Eldon Lindt

Commenter Affiliation: Xcel Energy Inc.

Document Control Number: EPA-HQ-OAR-2008-0508-2374.1

Comment Excerpt Number: 6

Comment: Under the proposed rule, large units (boilers and combustion turbines) and small onsite combustion sources such as space heaters and hot water heaters can attribute all emissions to the large unit provided that: 1) The total fuel supply is measured either at the "gate" or at a point inside the facility using a fuel flow, billing meter, or tank drop measurement; 2) At least 95 percent (by mass or volume) of shared fuel is combusted in the large unit; and 3) The Monitoring Plan lists the units that share the common fuel supply. For the small onsite combustion sources, a description and the approximate number of small sources is sufficient. Xcel Energy supports this revision because it clarifies how EPA expects facilities to report emissions from comfort heat, given that these sources most often use a common fuel supply line.

Response: EPA thanks the commenter for the input. We have finalized the amendments noted by the commenter as proposed.

Commenter Name: Stephen E. Woock

Commenter Affiliation: Weyerhaeuser Company

Document Control Number: EPA-HQ-OAR-2008-0508-2375.1

Comment Excerpt Number: 11

Comment: §98.36(c)(3): This proposed revision modifies the requirements associated with the common pipe reporting alternative. It allows a portion of the fuel measured at the main supply line that is diverted to a combustion unit covered under a different subpart to be subtracted out from the main flow, as long as the combustion emissions from the diverted fuel are accounted for in accordance with that subpart. Therefore, a facility may use company records to subtract out the diverted portion of fuel from that measured at the main supply line. This revision provides a straightforward and accurate alternative to account for fuel usage, and still comply with the applicable subpart requirements for each combustion unit. Weyerhaeuser supports this revision.

Response: EPA thanks the commenter for the input. We have finalized the amendments noted by the commenter as proposed.

Commenter Name: Fiji George

Commenter Affiliation: El Paso Corporation

Document Control Number: EPA-HQ-OAR-2008-0508-2390.1

Comment Excerpt Number: 8

Comment: Reporting requirements in 98.36(c)(1) - requirement to report the number of units in the group if using the aggregation method:

Current language, including changes proposed by the EPA:

“The number of units in the group.”

Proposed language with the requested changes in square brackets:

“The number of units in the group [or listing of units in the group. When small sources not related to the reporter primary business, such as space heaters, hot water heaters, and small process heaters are reported in addition to large combustion units, such as engines or large process heaters, they can be reported as a single domestic type source as long as emissions from these small sources are included in the total emissions.]”

The objective of the proposed change was to simplify the reporting requirements. However, many reporters, including El Paso, have already developed their reporting systems based on the originally promulgated regulation. Therefore, El Paso is requesting flexibility in reporting either the number of units in the group or listing each unit in the group. The best option would be to list all domestic type units as one source and provide the best available estimate of their combined heat input capacities. This reporting option will also be more representative of the facility and the domestic sources can be easily separated from the industrial sources as needed during verification.

For example, a compressor station operating five (5) natural gas fired compressor engines with a heat input capacity of 12 mmBtu/hr, ten (10) space heaters rated at 0.2 mmBtu/hr, and two (2) water heaters rated at 0.03 mmBtu/hr would report 17 emission units if the changes proposed by the EPA were implemented. However, only six (6) units would be reported if El Paso's proposed language was considered, i.e. the space heaters, hot water heaters, and small process heaters would be counted as one domestic type source rated at 2.06 mmBtu/hr. Reporting six (6) units is more representative because only five (5) units at the facility will be attributable to the majority of emissions. Typically, only when the domestic type sources are aggregated, their combined heat input capacity is in a range comparable to the heat input capacity of a process type emission unit. In addition, process type emission sources are well documented; the number of space heaters, water heaters and small process heaters might be estimated by the reporter. The overall accuracy of the report will decrease if well documented and estimated sources are reported as one number.

Response: See the response to comment EPA-HQ-OAR-2008-0508-2359.1, Excerpt 1.

Commenter Name: Fiji George

Commenter Affiliation: El Paso Corporation

Document Control Number: EPA-HQ-OAR-2008-0508-2390.1

Comment Excerpt Number: 9

Comment: El Paso proposes to allow reporters to combine the aggregation and common pipe methods. Under this approach, a reporter could aggregate units fueled by two or more common pipes for one or more units, provided that each of the emission units has a maximum heat input capacity of 250 mmBtu/hr or less. Fuel consumption under the hybrid approach will be established based on metered volumes for each common pipe.

Response: EPA disagrees with the commenter. Although both options are intended to allow facilities to report multiple units under one reporting methodology, the two options have distinctions that must be retained. The "aggregation of units" option is intended only to apply for units smaller than 250 mmBtu/hr and it allows units that burn multiple fuel types to be aggregated. The common pipe reporting option allows for emissions reporting from units larger than 250 mmBtu/hr, but it requires the common pipe to supply only one fuel type and the fuel must be measured at a common supply point. The common pipe reporting option applies only to liquid and gaseous fuels being supplied through a pipe. The aggregate reporting option is available for any fuel type. Referring to the commenter's example, since the units are all 250 mmBtu/hr or less, the aggregated group reporting option in §98.36(c)(1) may be used. Provided that the quantity of each fuel supplied to the group is known, it makes no difference that the fuels are supplied to the group through two separate common pipes.

Commenter Name: Robert Rouse

Commenter Affiliation: The Dow Chemical Company

Document Control Number: EPA-HQ-OAR-2008-0508-2366.1

Comment Excerpt Number: 11

Comment: EPA Should Allow Sources to Use Available Information When Using Provision to Aggregate Very Small Combustion Units.

The present rule in § 98.36(c)(I) requires sources that use the Aggregation Provision for small combustion units to provide the highest maximum rated heat input within the group and cumulative heat input of all units being aggregated. However, affected facilities can have numerous small combustion units, such as space heaters, water heaters and other furnaces, that are very old and their actual rated heat input capacity can not be determined. Therefore, we request EPA include a provision for these small units under the Aggregation of Units provision in § 98.36(c)(1) to use the actual cumulative heat input for such small older units. In addition, since it is impossible determine the highest maximum rated heat input for a unit within this group of old units, EPA must allow the use of actual cumulative heat input for this group.

Response: See the response to comment EPA-HQ-OAR-2008-0508-2359.1, Excerpt 1.

Commenter Name: Lauren E. Freeman

Commenter Affiliation: Utility Air Regulatory Group (UARG)

Document Control Number: EPA-HQ-OAR-2008-0508-2388.1

Comment Excerpt Number: 12

Comment: IX. Alternative Reporting Option for Facilities with Large and Small Combustion Units That Share A Common Liquid or Gaseous Fuel Supply

In its Reconsideration Petition, UARG expressed a number of concerns regarding application of Subpart C requirements for general stationary combustion units to small combustion units or activities that share a fuel supply with a Part 75 unit. Although EPA has proposed a number of revisions designed to eliminate some of the unnecessary burdens for such small units and activities, none of those provisions addressed the practice under Part 75 of measuring fuel use at one location (e.g., one tank or one meter at the fence line) and disregarding small fuel diversions when calculating and reporting emissions from larger combustion sources.

For example, some facilities with large units that combust oil or gas may use a small unmeasured portion of the fuel delivered to the facility for other uses and simply report emissions under other programs (like Part 75) as if all of the fuel delivered was combusted by the large combustion unit. This might occur when the amount of fuel diverted is so small compared to the amount combusted by the large unit that the overestimate in reported emissions is insignificant relative to other sources of error in the measurements. Because the rule currently provides no exception to the reporting requirements for Subpart D units for diversion of fuel to Subpart C units, if this practice were continued following promulgation of this rule, the rule would require sources to either ensure systems were in place to determine the amount of fuel diverted, or double count the emissions from the small combustion units by reporting the emissions under Subpart C as well.

To address this scenario, EPA proposes to revise § 98.36(c)(4) to allow simplified reporting for units with a common fuel supply where emissions from fuel supplied to small combustion sources is already reported (or can be reported) along with emissions from large combustion sources. 75 Fed. Reg. at 48,763. To ensure that the option is not applied to avoid separate reporting of emissions from large units, the option is limited to those circumstances where the source demonstrates using company records that at least 95 percent of the shared fuel supply is combusted in the large unit. The total quantity of the shared fuel supply also must be measured using a fuel flow meter, billing meter, or tank drop method. UARG appreciates the addition of this option, which is necessary to accommodate existing Part 75 reporting practices without requiring installation of new fuel measurement equipment. The option also will be useful to other facilities to avoid unnecessary fuel measurements without any sacrifice in data quality.

Response: EPA thanks the commenter for the input. We have finalized the amendments noted by the commenter as proposed.

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2008-0508-2383.1

Comment Excerpt Number: 25

Comment: API supports the revision of §98.36(b)(10) – Removed the requirement to report the customer meter number for units that combust natural gas.

Response: EPA thanks the commenter for the input. We have finalized the amendments noted by the commenter as proposed.

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2008-0508-2383.1

Comment Excerpt Number: 26

Comment: API supports the revision of §98.36(c)(1)(ii), (c)(2)(ii), and (c)(3)(ii) - Removed the requirement to report an identification number for each unit in the grouping of units, sharing the common stack or duct, or served by the common pipe. Instead, EPA proposes facilities report the number of units in the group.

Response: Please see response to comment EPA-HQ-OAR-2008-0508-2359.1, excerpt 1.

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2008-0508-2383.1

Comment Excerpt Number: 28

Comment: API supports the revision of §98.36(c)(3) – If a portion of the fuel measured at the main supply line is diverted to either a flare or another stationary combustion unit, company records may be used to subtract out the diverted portion of the fuel.

Response: EPA thanks the commenter for the input. We have finalized the amendments noted by the commenter as proposed.

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2008-0508-2383.1

Comment Excerpt Number: 29

Comment: API supports the revision of §98.36(c)(4) – New provision where liquid or gas fuel is shared between one of more large combustion units and small combustion units. Reporting may be simplified by attributing all of the shared fuel to the large combustion unit(s) provided (i) the total fuel quantity is measured (ii) 95% of the fuel is combusted in the large unit(s) (company records may be used to determine the percentage), and (iii) the use of this approach is documented in the Monitoring Plan.

Response: EPA thanks the commenter for the input. We have finalized the amendments noted by the commenter as proposed.

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2008-0508-2383.1

Comment Excerpt Number: 30

Comment: API supports the revision of §98.36(e)(2)(ii)(C) – Removed the requirement to report the date each fuel sample was taken for Tier 2.

Response: EPA thanks the commenter for the input. We have finalized the amendments noted by the commenter as proposed.

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2008-0508-2383.1

Comment Excerpt Number: 31

Comment: API supports the revision of §98.36(e)(2)(iii) – EPA proposes to revise the Tier 2 recordkeeping provision requiring records be maintained of the date of each fuel sample to

include an exception for cases where the sampling data is provided by the fuel supplier. In such cases, the reporters would be required to maintain a record of the date on which the analytic results were received.

Response: EPA thanks the commenter for the input. We have finalized the amendments noted by the commenter as proposed.

TABLE C-1

Commenter Name: Craig Holt Segall

Commenter Affiliation: Sierra Club Environmental Law Program et. al

Document Control Number: EPA-HQ-OAR-2008-0508-2398.3

Comment Excerpt Number: 10

Commenter Name: Helen D. Silver

Commenter Affiliation: Clean Air Task Force et. al

Document Control Number: EPA-HQ-OAR-2008-0508-2403.2

Comment Excerpt Number: 10

These two commenters submitted identical comments on this subject.

Comment: We are somewhat concerned that EPA proposes to redefine MSW and tires as “Other Fuels (Solid),” rather than as “Fossil-Fuel Derived Fuels.” See 75 Fed. Reg. at 48,674. Although this change appears to be entirely cosmetic, we still request that EPA carefully determine whether this definitional change would have any substantive impacts on MSW or tire burning facilities.

Response: The intent of changing the table grouping from “Fossil fuel-derived (solid)” to “Other fuels (solid)” was to recognize that there is a biogenic portion to both MSW and tires and these fuels are not entirely fossil-derived. The previous group listing seemed to indicate that there was no biogenic component in these fuels. The classification in Table C-1 was also inconsistent with the rule text because methods were provided in §98.34(d) to calculate biogenic CO₂ emissions from MSW. Other than clarifying that MSW and tires are not entirely fossil-derived, there is no impact from this change---it has no effect on how emissions from the combustion of MSW or tires are calculated and reported. There will be no loss of coverage as a result of this change. Please see section II.F of the proposal preamble (75 FR 48754).

Commenter Name: Kerry Kelly

Commenter Affiliation: Waste Management (WM)

Document Control Number: EPA-HQ-OAR-2008-0508-2360.1

Comment Excerpt Number: 2

Comment: WM supports the proposed categorization of MSW and Tires in Table C-1 as “other fuels (solid)” as a needed clarification. EPA correctly notes that MSW and tires are not appropriately termed “fossil fuel-derived fuels” because both have a biogenic component. In fact, a significant majority of MSW material produced in the U.S. is of biogenic origin – fully 65 percent on average.

Response: EPA thanks the commenter for the input. We have finalized the amendments noted by the commenter as proposed.

Commenter Name: Kerry Kelly

Commenter Affiliation: Waste Management (WM)

Document Control Number: EPA-HQ-OAR-2008-0508-2360.1

Comment Excerpt Number: 3

Comment: We do, however, question the appropriateness of listing MSW with plastics and petroleum coke. Petroleum coke is listed twice in the table, first under petroleum products and then again under “other fuels (solid).” As a petroleum derivative, petroleum coke is more appropriately listed with the other “petroleum products.”

Response: See Section II.G of the preamble to the final rule amendments for the response to this comment.

Commenter Name: Kerry Kelly

Commenter Affiliation: Waste Management (WM)

Document Control Number: EPA-HQ-OAR-2008-0508-2360.1

Comment Excerpt Number: 4

Comment: Further, EPA has called out plastics as a fuel for the first time in the GHG MRR. Plastics are a small component of MSW – according to EPA plastics comprise only 12 percent of MSW in the U.S. There is no discussion of why EPA now feels the need for the first time to highlight plastics as a separate fuel stream, and we recommend that the listing be deleted as it serves no useful purpose. We are unaware of segregated plastics being commonly used as a fuel stream by stationary combustors.

Response: Note that another commenter has stated that plastics are sometimes recovered from MSW and burned separately (see the response to EPA-HQ-OAR-2008-0508-2401.1, Excerpt 1).

Commenter Name: John H. Skinner

Commenter Affiliation: Solid Waste Association of North America (SWANA)

Document Control Number: EPA-HQ-OAR-2008-0508-2397.1

Comment Excerpt Number: 2

Comment: The Solid Waste Association of North America (SWANA) agrees with EPA’s decision to re-classify municipal solid waste and tires as “other fuels” in table C-1 of Subpart C. The classification of them as fossil fuel derived ignores the fact that the majority of emissions from the combustion of these sources are biogenic in nature.

Response: EPA thanks the commenter for the input. We have finalized the amendments noted by the commenter as proposed.

Commenter Name: Ted Michaels

Commenter Affiliation: Energy Recovery Council (ERC)

Document Control Number: EPA-HQ-OAR-2008-0508-2393.1

Comment Excerpt Number: 2

Comment: The proposed corrections to Table C-1 fuel categories provide appropriate and necessary clarification. The Energy Recovery Council (ERC) supports the proposed categorization of MSW and Tires in Table C-1 as “other fuels (solid)” as a needed clarification. EPA correctly notes that MSW and tires are not appropriately termed “fossil fuel-derived fuels” because both have a biogenic component. In fact, a significant majority of MSW material produced in the U.S. is of biogenic origin, fully 65 percent on average. We may suggest however that consistent with other proposed clarifying language in 40 CFR 98 (See 98.34(e)), it would be more appropriate to include tires and MSW in Table C-1 under the category “heterogeneous fuels (solid)”.

We do question the appropriateness of listing MSW with plastics and petroleum coke which have no biogenic component since both are derived exclusively from fossil fuels. Petroleum coke is listed twice in the table, first under petroleum products and then again under “other fuels (solid).” As a petroleum derivative, petroleum coke is more appropriately listed with the other “petroleum products.” Plastics are a small component of MSW – according to EPA, plastics comprise only 12 percent of MSW in the U.S. There was no discussion of why EPA feels the need to include plastics now as a separate fuel stream, and we recommend that the listing be deleted consistent with the final rule, as it serves no useful purpose. We are unaware of segregated plastics being commonly used as a fuel stream by stationary combustors.

Response: See Section II.G of the preamble to the final rule amendments for the response to this comment.

Commenter Name: Walter Tyler

Commenter Affiliation: INVISTA

Document Control Number: EPA-HQ-OAR-2008-0508-2372.1

Comment Excerpt Number: 3

Comment: The inclusion of “Fuel Gas” emission factors on Table C-1 was clearly established for the convenience of Subpart X and Subpart Y facilities, however, Footnote 2 associated with the emission Fuel Gas factors could be interpreted to require facilities not subject to Subpart X or Subpart Y to monitor and report GHG emissions from process waste off-gas streams. Consistent with the comments above on the definition of fuel, INVISTA recommends that footnote 2 to Table C-1 be rewritten as follows to clarify the applicability of the Fuel Gas emission factors:

“Reporters subject to subpart X of this part that are complying with § 98.243(d) or subpart Y of this part may only use the default HHV and the default CO₂ emission factor for fuel gas combustion under the conditions prescribed in § 98.243(d)(2)(i) and (d)(2)(ii) and § 98.252(a)(1) and (a)(2), respectively. Otherwise, reporters subject to subpart X or subpart Y shall use either Tier 3 (Equation C–5) or Tier 4.

Response: We agree with the commenter. In the final rule, footnote 2 below Table C-1 has been modified, as requested.

Commenter Name: David A. Buff

Commenter Affiliation: Golder Associates Inc.

Document Control Number: EPA-HQ-OAR-2008-0508-2395.1

Comment Excerpt Number: 3

Comment: Table C-1 contains default high heating values (HHV) for various types of fuels. For “Biomass Fuels – solid”, the default value in the table is 8.25 mmBtu/short ton. It is presumed that this value is for short tons as received, as opposed to short tons on a dry basis. However, due to the large difference between HHV of wet vs. dry biomass fuels, this should be clearly stated in the table. Even with this clarification, the HHV of solid biomass fuels may vary greatly. For example, sugarcane bagasse is typically 3,600 – 4,200 Btu/lb, wet basis (approx. 50-55% moisture as received) (7.2 to 8.4 mmBtu/short ton). However, rice hulls or peanut shells may in fact have a much higher heating value since these materials are relatively dry. To more accurately reflect actual heating values for a particular type of biomass (and more accurately report GHG emissions), the rule should allow published data, best available data, industry standards, etc., to be used in lieu of the default values. The HHV and the justification/rationale for the values can be required to be incorporated into the GHG monitoring plan.

Response: The purpose of Table C-1 is to provide default HHV and emission factor values that can be used by reporters, where appropriate, and therefore simplify emissions reporting. The default value of 8.25 mmBtu/short ton is on a dry-basis. We recognize that not all biomass fuels will be combusted on a dry-basis, however for the purposes of a default value we have concluded that this value is sufficient to represent the potential range of HHVs of the fuels, as combusted. We do not agree that it is necessary to allow published data, best available data, industry standards, etc. to be used in the emissions calculations for HHVs of biomass fuels- solid. If the commenter wants a more refined HHV than what is strictly required by the reporting rule, they

may use a Tier 2 or Tier 3 methodology, and therefore a site-specific HHV, instead of the Tier 1 methodology for calculating emissions from biomass.

Commenter Name: Lorraine Krupa Gershman

Commenter Affiliation: American Chemistry Council

Document Control Number: EPA-HQ-OAR-2008-0508-2368.1

Comment Excerpt Number: 5

Comment: The proposed addition of the term “fuel gas” to Table C-1 with no modification to the current “fuel gas” definition results in additional impacts that EPA should clarify in the final rule. ACC understands “still gas” was removed from Table C-1 and “fuel gas” was added to Table C-1 as part of a settlement agreement to address concerns with a provision specific to petroleum refineries in Subpart Y that requires refineries to calculate CO₂ emissions from the combustion of refinery fuel gas using either Tier 3 or Tier 4 methodology. “Fuel gas,” as defined in subpart A, “means gas generated at a petroleum refinery, petrochemical plant, or similar industrial process unit, and that is combusted separately or in any combustion with any type of gas.”

Due the definition of fuel gas, the addition of “fuel gas” to Table C-1 affects petrochemical plants in addition to petroleum refineries, and could be interpreted to include process off-gas derived from processes that are not subject to Subpart X or Y. The proposed revision to add “fuel gas” to Table C-1 will result in numerous “fuel gas” streams at petrochemical plants and possibly others now being subject to the MRR requirements. ACC recommends that EPA: revise the entry in Table C-1 to “refinery fuel gas” instead of “fuel gas” and modify the definition of “fuel gas” in 98.6 to stipulate this refers to “refinery fuel gas” only; and, (2) clarify the calculation and reporting of emissions from “fuel gas” streams is not required until the 2011 reporting year, with the annual report due by March 31, 2012, since “fuel gas” was added to Table C-1 during the 2010 reporting year and thus reporters could not comply with the requirement as of January 1, 2010.

Response: Please see response to comment EPA-HQ-OAR-OAP-2008-0508-2366.1, excerpt 4.

Commenter Name: Bryan Brendle

Commenter Affiliation: Portland Cement Association

Document Control Number: EPA-HQ-OAR-2008-0508-2399.1

Comment Excerpt Number: 4

Comment: EPA also proposes to broaden the proposed categories for various fossil-fuel derived fuels. More specifically, EPA is proposing some changes to Table C-1 to expand the meaning of “solid and gaseous fossil fuel derived fuels” to include plastics, municipal solid waste, tires and petroleum coke for solids, and blast furnace gas, coke oven gas, propane gas, and fuel gas for gaseous fuels.” PCA believes these changes add flexibility.

Response: EPA thanks the commenter for the input. We have finalized the amendments noted by the commenter as proposed.

Commenter Name: Craig Holt Segall

Commenter Affiliation: Sierra Club Environmental Law Program et. al

Document Control Number: EPA-HQ-OAR-2008-0508-2398.1

Comment Excerpt Number: 14

Comment: First, as we stated in comments on the proposed settlement agreement, we are concerned with EPA's proposal to redefine MSW and tires as "Other fuels (solid)". EPA states that "overall we do not believe that the changes between the proposed and final Part 98, nor the amendments [described in this proposed rulemaking], have a substantive impact on the calculation requirements or the reporting of emissions for MSW or tires under this rule." While it may be the case that this change is entirely cosmetic, we nonetheless continue to request that EPA determine "whether this definitional change would have any substantive impacts on MSW or tire burning facilities."

Response: Please see response to comment EPA-HQ-OAR-2008-0508-2403.2, excerpt 10 for the response to this comment.

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2008-0508-2383.1

Comment Excerpt Number: 15

Comment: For refinery applications, API supports the replacement of the emission factor and higher heating values listed for "still gas" in Subpart C, Table C-1. However, for the purposes of reporting under Subpart X, adding a default factor for "fuel gas" versus "refinery fuel gas" could have a negative impact on chemical plant fuel gas streams that were previously exempt from Tier 3 requirements (e.g., the streams provide < 10% of the annual heat input to a unit rated > 250 MMBtu/hr) because previously there was no fuel gas factor in the Table C-1.

Without the addition of "refinery" to the "fuel gas" information in Table C-1, a timing compliance issue results. Petrochemical gas stream that were previously exempt from reporting must now be metered and sampled weekly to comply with the Tier 3 requirements. In such cases, installation of new meters may be required. There is no retroactive BMM period until such meters are installed. As a result, complying with the sampling, calibration, and reporting requirements for Tier 3 is not feasible given that most of 2010 is past.

API requests that EPA change the label in Table C-1 to "refinery fuel gas".

Response: Please see response to comment EPA-HQ-OAR-OAP-2008-0508-2366.1, excerpt 4

Commenter Name: Karin Ritter
Commenter Affiliation: American Petroleum Institute (API)
Document Control Number: EPA-HQ-OAR-2008-0508-2383.1
Comment Excerpt Number: 17

Comment: API supports the August 11, 2010 proposed revision to the natural gas entry in Table C-1 that removes the word “pipeline”, which allows reporters to use the Tier 1 or Tier 2 CO₂ emissions calculation methodology for either field quality or pipeline quality natural gas. However, EPA’s proposed change to the definition of natural gas negate the revision to Table C-1.

Response: In the final rule we have withdrawn the proposed HHV and methane content specifications in the definition of natural gas. See Section II.G of the Preamble for further discussion.

Commenter Name: Craig Holt Segall
Commenter Affiliation: Sierra Club Environmental Law Program et. al
Document Control Number: EPA-HQ-OAR-2008-0508-2398.1
Comment Excerpt Number: 19

Comment: First, EPA requests comment on “new and revised fuel categories” in Table C-1. 75 Fed. Reg. at 48,764. We recommend that EPA add an additional category of “waste coal”, including gob and boney (bituminous waste) and culm (anthracite waste) left behind by coal mining. These fuels are in common use in circulating fluidized bed boilers (CFBs) and should be accounted for in the reporting rule.

CFBs are able to burn a wider range of fuels than most other coal-fired boilers. This has made them particularly attractive as “waste coal” burners, as they can be used to burn the gob, boney, and culm left behind by coal mining. Waste coal-fired CFBs comprise a significant category of boilers. Reliant Energy’s Seward station, for instance, has two 260 MW units and is designed to burn almost exclusively coal waste. One comprehensive reference reports that “[w]ith the advent of CFB technology and its application to this fuel, there has been a significant increase in the use of anthracite culm and bituminous gob within the USA,” charting an increase from just 1.3-1.4 million tons used in 1989 to 8.9-9.3 million tons burned in 2001.⁴⁷ This increase is attributable, almost entirely, to CFBs.

Indeed, according to EPA, there are currently 18 plants burning waste coal as a primary fuel, and 13 plants using waste coal as a secondary fuel. EPA records 17 additional plants that have been proposed and are in some phase of project development. According to EPA, every one of these plants uses CFB technology.

The upshot is that, as these waste coal burners operate and come online, it becomes increasingly important both to understand any unique factors associated with using waste coal as a fuel. We

urge EPA to develop emissions factors for this fuel, taking into account its carbon dioxide, methane, and nitrous oxide emissions.

Response: No rule change has been made as a result of this comment at this time. EPA agrees with the commenter that the HHV and other characteristics of waste coal such as culm and gob are distinctly different from those of anthracite and bituminous coal. However, we have concluded that it is not necessary to provide default HHVs and CO₂ emission factors for these fuels in Table C-1 because the units that burn these fuels (including the Seward station mentioned by the commenter) are located principally in the Northeastern United States and are equipped with the CEMS that are needed to measure CO₂ mass emissions. Therefore, most, if not all of them, are in the Acid Rain Program, and are subject to Subpart D of Part 98. If additional information is made available in the future to indicate that others combust this fuel in relevant quantities, we will reconsider whether this fuel should be added to Table C-1.

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2008-0508-2383.1

Comment Excerpt Number: 54

Comment: Corrections to Tables C-1 and C-2:

- a. Given that reporting under the MRR begins January 2010, the fuel factors used in the most recent EPA national inventory would be more appropriate than values cited three years ago.
- b. The heating values cited in the MRR for residual fuel #5 and ethane are notably different from values cited in the 2009 API Compendium (7% for residual fuel #5 and 37% for ethane). For ethane, the value cited in the MRR appears to be a mistype; 0.096 MMBtu/gal, where the TSD indicates 0.069 MMBtu/gal (the Compendium value is 0.070 MMBtu/gal). For residual fuel oil #5, the TSD showed 0.150 MMBtu/gal, where the value in the final rule is 0.140 MMBtu/gal (the Compendium value is 0.150 MMBtu/gal).
- c. The EPA MRR emission factors for municipal solid waste appear to have an error in the units.
- d. The natural gas factors shown in the MRR appear to have applied the liquid or solid fuel conversion from LHV to HHV, rather than the gas fuel conversion. Similarly, for the N₂O emission factor for coke oven gas.
- e. There appears to be round-off differences or errors in adjusting from LHV to HHV for groupings of emission factors (most of the liquid fuel and solid fuel factors).
- f. The CH₄ emission factor for coke oven gas shown in the MRR is approximately one-half the value reported by IPCC and cited in the Compendium.

g. The MRR emission factors differ from the IPCC factors for LPG and ethane. Where IPCC aligns the emission factors for these sources with other gaseous fuels, the MRR applies emission factors used for other liquid fuels.

h. Other notable differences were observed in comparing the MRR emission factors for peat, biodiesel, and biogas to the API Compendium. However, the reason for the difference is not clear without knowing the source of the MRR values.

i. EPA should provide an explanation for the change from factors cited in the TSD and should also provide a citation for the factors.

Response: We thank the commenter for the input. Several of the specific comments above are outside the scope of the proposed amendments and no rule change has been made as a result of those comments. The proposed rule solicited comment on amendments to specific fuel types and categories listed in Table C-1, and specifically requested comment on the (1) the new and revised fuel categories; (2) the appropriateness of the HHVs and CO₂ emission factors for the fuels listed in these categories; and (3) whether additional fuels should be included in Table C-1, and if so, what the HHVs and CO₂ emission factors for those fuels should be. We address the in-scope comments below.

In developing the rule in 2008, EPA relied on the latest statistical information on national fuel consumption and characteristics available, as published in EIA's Annual Energy Review. Subsequently, EIA updated heat content values, and the changes in factors from the TSD are due to those changes. The citation for the changes is based on data in the EIA Annual Energy Review 2008 (publication DOE EIA-0384(2008)).

We did not propose changes to residual fuel #5 and #6 and therefore have not made any changes to these HHVs or default emission factors in the final review. We did review the concern about ethane and identified a transcription error in the final rule that we have corrected. The TSD was correct and the ethane emission factor should be 0.069 mmBtu/gal, close to the value in the API Compendium.

The emission factor of 90.7 kgCO₂/mmBtu is consistent with the California Air Resources Board (ARB) rulemaking for mandatory reporting of greenhouse gas emissions, as approved and adopted by the State of California on December 2, 2008 for reporting beginning on January 1, 2009 (see: <http://www.arb.ca.gov/regact/2007/ghg2007/ghg2007.htm>).

The natural gas factors were taken from the Energy Information Administration Annual Energy Review, Table A-4, where EIA reports the high heating value. The emission factors are derived from the latest official *Inventory of U.S. GHG Emissions and Sinks*, based on its examination of the carbon contents and composition of the average pipeline quality natural gas in the United States, as described in Annex 2.2 of the *Inventory* report. The HHV data come from EIA, so it is not clear what the commenter means by EIA used the wrong LHV to HHV conversion.

Regarding the methane emission factor for coke oven gas (COG), we agree that the value is different from the one presented by the Intergovernmental Panel on Climate Change and the API Compendium. We tried to tailor it more to the circumstances in the iron and steel industry. To do this, we started with default high heat values from Gannon, H.E. (editor) *The Making, Shaping and Treating of Steel*, Tenth Edition (1985), Page 131. The calculation is presented below.

For Coke oven gas (using 28% CH₄ from reference above):

$$\frac{(1.03 \times 10^{-6} \text{ kg } CH_4 / \text{scf } CH_4)(0.28 \text{ scf } CH_4 / \text{scf } COG)}{5.99 \times 10^{-4} \text{ mmBtu} / \text{scf } COG} = 4.8 \times 10^{-4} \text{ kg } CH_4 / \text{mmBtu}$$

The API observation regarding LPG and ethane is correct. We understood that as the fuels leave the refinery gate they are under pressure and hence are in the liquid state. Therefore we revised the density and carbon content to reflect the LPG components as liquid rather than gas. Please see the discussion from the MRR definitions document at:

<http://www.epa.gov/climatechange/emissions/downloads09/documents/SubpartMMProductDefinitions.pdf>

We have not proposed changes to the emission factors for peat and biogas, therefore these comments are out of scope of this rulemaking and no change has been made as a result of this comments. The high heating value for biodiesel of 0.128 mmBtu/gal was taken from the EIA Annual Energy Outlook and the emission factor was converted from the value in the EPA Climate Leaders reference materials

(http://www.epa.gov/climateleaders/documents/resources/mobilesource_guidance.pdf). EPA has chosen to use the Climate Leaders default emission factors provided in their guidance, as it was believed that, in conjunction with the partners to this program, these values represent a generally applicable default value for these variable fuel types.

As described above, we will continue to evaluate heating values and emission factors as new data become available. In Table C-1, EPA provided reporters with average U.S. values for fuel characteristics, based on national statistics collected by EIA, for use with the tier 1 and tier 2 methodologies. Reporters, as stated in the rule, are welcome to use a higher tier, if they believe that use of such a higher tier method would better represent emissions from stationary combustion sources.

TABLE C-2

Commenter Name: Anonymous

Commenter Affiliation: None

Document Control Number: EPA-HQ-OAR-2008-0508-2350

Comment Excerpt Number: 2

Comment: In Table C-2, Plastics, Petroleum Coke, Propane Gas, and Fuel Gas were omitted.

Response: EPA did not propose to add default emission factors to Table C-2 for Plastics, Petroleum Coke, Propane Gas, and Fuel Gas. Consistent with §98.33(c), facilities are not required to calculate and report CH₄ and N₂O emissions from these fuels as they are not listed in Table C-2. EPA will consider adding default emission factors for these fuels in the future.

Commenter Name: Craig Holt Segall

Commenter Affiliation: Sierra Club Environmental Law Program et. al

Document Control Number: EPA-HQ-OAR-2008-0508-2398.1

Comment Excerpt Number: 20

Comment: Importantly, these nitrous oxide emissions may be quite high, at least in the context of CFBs, which brings us to our second suggestion. EPA has long recognized that the low combustion temperatures associated with CFBs generates far more N₂O than the higher temperatures in other boilers. EPA should therefore revise Table C-2 to include a distinct N₂O emissions factor for CFBs.

As EPA writes in its Compilation of Air Pollutant Emissions Factors (generally referred to as “AP-42”):

Formation of N₂O during the combustion process is governed by a complex series of reactions and its formation is dependent upon many factors. Formation of N₂O is minimized when combustion temperatures are kept high (above 1575 °F) and excess air is kept to a minimum (less than 1 percent). N₂O 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.

For this reason, AP-42 distinguishes CFBs from all other coal boilers. Although it sets emissions factors of between 0.03-0.09 lb/tons for all other boilers, it provides an emission factor of 3.5 lb/ton for both CFBs and bubbling fluidized bed boilers. This factor works out to be about 67.3 g/mmBtu for bituminous coal and 92.0 g/mmBtu for sub-bituminous coal. The present Table C-2 N₂O factor for all coal-fired boilers, by contrast, is set at 1.6 g/mmBtu, an order of magnitude different.

This undercounting is a serious problem, particularly because N₂O’s global warming potential is roughly three hundred times that of carbon dioxide. EPA should take this opportunity to correct this error. Using the existing AP-42 factors would be one fairly straightforward way to make this fix.

Response: No rule change has been made as a result of this comment. On August 11, 2010, we did not propose changes to the N₂O emission factor for coal-fired units and therefore the specific recommendations are outside of the scope of this rulemaking. However, we thank the commenter for the input. We note that the suggested emission factors provided by the commenter are for bituminous coal and sub-bituminous coal. No factors were provided for

waste coal (i.e., culm, gob, and boney), which is the principal fuel in many of the CFB units in the U.S. We intend to undertake additional research and, as appropriate, would make any future changes to the N₂O emission factor through a rulemaking.

OTHER SUBPART C COMMENTS

Commenter Name: David A. Buff

Commenter Affiliation: Golder Associates Inc.

Document Control Number: EPA-HQ-OAR-2008-0508-2395.1

Comment Excerpt Number: 4

Comment: In Subpart C, several references are made to “secondary fuels”. However, there is no definition of secondary fuels in the rule. Is a secondary fuel any fuel other than the primary fuel? This should be defined.

Response: EPA has amended the requirements under 40 CFR 98.33(b)(4)(ii)(B) to remove the term secondary fuel, which was undefined and caused considerable confusion.

Commenter Name: Rich Raiders

Commenter Affiliation: Arkema Inc.

Document Control Number: EPA-HQ-OAR-2008-0508-2371.1

Comment Excerpt Number: 4

Comment: The Subpart C applicability provisions clarify existing fuel blend requirements.

Response: EPA thanks the commenter for the input. We have finalized the amendments noted by the commenter as proposed.

Commenter Name: Robert Rouse

Commenter Affiliation: The Dow Chemical Company

Document Control Number: EPA-HQ-OAR-2008-0508-2366.1

Comment Excerpt Number: 3

Comment: EPA Should Add Alternatives to the Requirements for Tier 3 Fuels that Contain Less than 1 wt% Carbon.

EPA should add one or more alternatives to Subpart C of the GHG Reporting Rule for Tier 3 Fuels that contain less than 1 wt% carbon. An example of such a fuel is a hydrogen fuel stream that contains trace levels of carbon compounds. Currently, sources are required to sample these streams on a weekly basis in order to determine the carbon content and the molecular weight. This activity adds very little value to the quality of the GHG emission calculation even for

combustion sources with a heat input > 250 MMBtuIhr. Therefore, the following alternatives should be considered in the reporting rule:

1. The rule should allow the use of a default value for the carbon content (CC) up to 0.01 and for the use of engineering calculations to determine the molecular weight of the stream (MW). These values can be determined based on previous test results or other readily available information.
2. The rule could also allow the use of the Tier 1 emission calculation approach using the proposed emission factors for Fuel Gas in Table C- I.

Option #1 would result in more accurate GHG emission calculations, but both options would streamline the data collection requirements for Tier 3 fuels with very low carbon contents.

Response: No rule change has been made as a result of this comment. The changes to Part 98 suggested by the commenter are outside the scope of the amendments proposed for public comment in the Federal Register notice of August 11, 2010.

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2008-0508-2383.1

Comment Excerpt Number: 21

Comment: API supports the revision of §98.30(d) – You are not required to report GHG emissions from pilot lights (defined as small, permanent auxiliary flame that ignites the burner of a combustion device when the control valve opens).

Response: EPA thanks the commenter for the input. Note that in the final rule, we removed the word “permanent” from the definition of “pilot light”.

4. SUBPART D - ELECTRICITY GENERATION

Commenter Name: Brady W. Wassom

Commenter Affiliation: Environmental Systems Corporation (ESC)

Document Control Number: EPA-HQ-OAR-2008-0508-2367.1

Comment Excerpt Number: 1

Comment: Environmental Systems Corporation (ESC) supports the revision to the Mandatory Reporting Rule allowing the use of records retained under 40 CFR 75.57(h) for missing data events to satisfy the recordkeeping requirements of §98.3(g)(4) for those same events. This revision will reduce the recordkeeping burden on our customers and eliminate duplicate recordkeeping procedures.

Response: EPA thanks the commenter for the input. We have finalized the amendments, as proposed.

5. SUBPART F - ALUMINUM PRODUCTION

Other Subpart F Comments

Commenter Name: Robert P. Strieter

Commenter Affiliation: The Aluminum Association, Inc.

Document Control Number: EPA-HQ-OAR-2008-0508-2362.1

Comment Excerpt Number: 1

Comment: The Aluminum Association supports all of the proposed technical corrections included for Subpart F applicable to primary aluminum production. EPA has effectively addressed all of the technical concerns with reporting GHG emissions from primary aluminum production under the final rule published in October 2009.

We appreciate the efforts of the EPA technical staff in satisfactorily addressing the reporting, calculation, monitoring and data estimation issues for primary aluminum that we outlined in the final rule.

Response: EPA thanks the commenter for the input. We have finalized the amendments, as proposed.

6. SUBPART G - AMMONIA MANUFACTURING

Purge Gas/Recycle Stream

Commenter Name: Tom Siegrist

Commenter Affiliation: Koch Nitrogen Company LLC (KNC)

Document Control Number: EPA-HQ-OAR-2008-0508-2364.1

Comment Excerpt Number: 2

Comment: EPA has correctly concluded that reporting of emissions associated with the waste recycle or purge stream, under the Ammonia Manufacturing subcategory, is not needed in order to accurately characterize emissions from this subcategory. (75 FR 48766)

EPA has proposed to eliminate the calculation, monitoring and reporting of emissions associated with the waste recycle stream or purge currently required by Equation G-6. Whereas the carbon contained in the waste recycle or purge has already been accounted for elsewhere through consideration of the feedstock carbon content, it would be technically incorrect to double-count

that same carbon through calculation of an additional emission estimate associated with use of the purge as a fuel. EPA is also proposing to amend 40 CFR 98.72(b) to indicate that subpart C (general stationary fuel combustion sources) does not apply to CO₂ emissions from the use of purge gas as fuel. Koch Nitrogen Company, LLC (KNC) supports both of these proposed changes as means to improve the accuracy of the resulting emissions estimates.

Response: EPA thanks the commenter for the input. We have finalized the amendments, as proposed.

Proposed Deletion of Synthetic Fertilizer Reporting

Commenter Name: William C. Herz

Commenter Affiliation: The Fertilizer Institute (TFI)

Document Control Number: EPA-HQ-OAR-2008-0508-2376.1

Comment Excerpt Number: 2

Comment: Equating Fertilizer Production And Fertilizer Sales With Fertilizer Application Is Not Appropriate. EPA suggests two rationales for removing the requirement to report the total pounds of synthetic fertilizer and the total nitrogen contained therein. First, EPA states that “[t]he data that would be reported under these subparts do not provide directly applicable information with which to determine N₂O emissions from application of fertilizer because the data are incomplete.” (75 FR 48767) EPA is correct that the data are incomplete, with more than 56.4 percent of the U.S. nitrogen fertilizer supply being imported and nitrogen fertilizer produced domestically outside of the ammonia and nitric acid production industries not subject to reporting under the Rule. Thus, EPA would be missing a large amount of data and it will be impossible to generate any meaningful information from the limited data received. In addition, the overall percentage would be far less than 43.6 percent as important inputs such as manure, biosolids, and nitrogen from atmospheric deposition also are uncounted. These organic sources tend to volatilize N₂O at far higher rates per unit nitrogen than commercial fertilizer.

More importantly, however, TFI does not believe that reporting the total pounds of synthetic fertilizer and the total nitrogen contained therein bears any correlation to the “application of fertilizer” to agricultural soils. This is evidenced by data reported to EPA as part of the 2006 Inventory Update Reporting (IUR) Program. For 2006, EPA required chemical manufacturers of organic chemicals to report for the first-time down-stream processing and use data for their chemical substances to the extent that the chemical substances were manufactured and/or imported at the site in quantities of at least 300,000 pounds during calendar year 2005. 40 C.F.R. § 710.52(c)(4).

In particular, EPA required manufacturers exceeding the reporting threshold to report: (1) a designation indicating the “type of processing or use operation” at each site that received the reported chemical substance (with five options); (2) the five-digit North American Industrial Classification System (NAICS) code which best describes each processing or use operation; and (3) an “industrial function category” (with 33 options) corresponding to the type of processing or

use operation/NAICS code for each down-stream activity. Notably, “agricultural chemicals (non-pesticidal)” is one of the 33 “industrial function categories.”

Based on a review of aggregate IUR data for urea, five “industrial functions categories” in addition to “agricultural chemicals (non-pesticidal)” were identified by manufacturers and importers of urea: (1) “adhesives and binding agents;” (2) “reducing agents;” (3) “process regulators, used in vulcanization or polymerization processes;” (4) “coloring agents, dyes;” and (5) “processing aid, not otherwise listed.”

Further, even as to the “agricultural chemicals (nonpesticidal)” category, this category does not correspond to 100 percent of the urea being land applied. Rather, it would include blending or mixing of urea with other fertilizers and the sale of urea directly to an end user. Thus, attributing 100 percent of urea production to fertilizer application is incorrect, and assuming that 100 percent of a product fertilizer that is sent to an agricultural retail facility is applied to the ground is incorrect. The same flaws would apply to other synthetic fertilizers.

Second, EPA states as its second rationale for deleting the fertilizer production and nitrogen content reporting requirements that the data are currently available from the Association of American Plant Food Control Officials (AAPFCO). (75 FR 48767) According to EPA, “[t]he sales data is [sic] equivalent to fertilizer application since the sales are from the last licensed dealer.” Id. As with reporting the total amount of fertilizer produced and the nitrogen content of same has no usefulness to determining the amount of fertilizer applied to agricultural soils, the AAPFCO data, although useful in tracking sales to a dealer, does not necessarily mean that the fertilizer sold to the dealer is ultimately applied to the ground. A given quantity of nitrogen fertilizer may be sold multiple times before reaching an agricultural field (e.g., from a distributor to a blending operation to a retailer), which results in multiple additions of the same quantity of fertilizer. Further, the AAPFCO data includes fertilizer sales for both agriculture and non-agricultural purposes. The EPA Science Advisory Board draft report on reactive nitrogen states:

The UFTRS (the AAPFCO Commercial Fertilizers data set) was not designed to track the source of inorganic nutrients applied to agricultural land on the geographic scale needed for watershed modeling. The system only tracks sales of synthetic fertilizers and not manure or biosolids applied to farmland. In addition, geographical data associated with each sale may or may not be near the actual point of application. [Footnote: EPA Science Advisory Board, Reactive Nitrogen in the United States – An Analysis of Inputs, Flows, Consequences and Management Options, pg. 37 (May 28, 2010).]

Because of the limited data set for reported synthetic fertilizer production and nitrogen content of same, and the inability to extrapolate this data to application of fertilizer to agricultural soils, TFI supports EPA’s proposal to delete the requirement to report synthetic fertilizer production and the nitrogen content in the fertilizer.

Response: Without necessarily agreeing with all of the commenter’s argument, we have finalized the amendments, as proposed. Please see Section II.J of the preamble to the final rule amendments for the response to this comment.

Commenter Name: Craig Holt Segall
Commenter Affiliation: Sierra Club Environmental Law Program et. al
Document Control Number: EPA-HQ-OAR-2008-0508-2398.3
Comment Excerpt Number: 13

Commenter Name: Helen D. Silver
Commenter Affiliation: Clean Air Task Force et. al
Document Control Number: EPA-HQ-OAR-2008-0508-2403.2
Comment Excerpt Number: 13

These two commenters submitted identical comments on this subject.

Comment: As EPA writes in its proposed rule, “[n]itrous oxide emissions from agricultural soils are an important source of greenhouse gas emissions in the United States (approximately 3 percent in 2008).” (75 FR 48767) Accurately tracking fertilizer production, which drives 26% of emissions from this source, is therefore essential to tracking and reducing N₂O emissions. We praised EPA’s decision to include this requirement in the final rule and are dismayed that EPA is now considering waiving it to settle with The Fertilizer Institute (“TFI”).

The TFI settlement would have EPA delete its requirement that facilities report on urea production and on “total pounds of synthetic fertilizer and total nitrogen contained in that fertilizer.” 75 FR 48767; 40 C.F.R. §§ 98.76(b)(16), (b)(17), & (c). EPA offers no coherent reason for this deletion.

First, EPA states that domestic producers produce “less than one-half of the total amount of nitrogen-based fertilizer used in the United States.” 75 FR 48767. Surely this is a good reason to monitor their production and, if possible, to extend monitoring to imports and other sources. It does not justify waiving reporting entirely.

Second, EPA suggests that it has some sales data from the Association of American Plant Food Control Officials (“AAPFCO”) which can address “near-term analytical needs.” Id. But EPA admits that AAPFCO’s data comes from state sources where “AAPFCO has indicated in a published article that recent stresses on state budgets potentially threaten the continued availability of these data.” Id. So this data, which is not supplier-specific and does not necessarily cover all reporting rule requirements, may soon vanish and does not, in any event, map back onto specific facilities, which EPA must track under the reporting rule mandate. EPA’s two justifications do not make sense. EPA acknowledges that it needs N₂O data, that fertilizer production data begins to fill this need, and that other data sources are not generally adequate and may vanish entirely. Indeed, EPA acknowledges that it is poised to “initiate a fertilizer reporting requirement” when these sources fail, and that it should expand its reporting to cover “elements such as fertilizer application rates, timing of application, and the use of slow-release fertilizers and nitrification/urease inhibitors.” Id.

Given these acknowledged needs, it is perverse to drop the requirements EPA already has. We urge EPA not to do so.

Response: Please see Section II.J of the preamble to the final rule amendments for the response to this comment.

Commenter Name: William C. Herz

Commenter Affiliation: The Fertilizer Institute (TFI)

Document Control Number: EPA-HQ-OAR-2008-0508-2376.1

Comment Excerpt Number: 3

Comment: On July 20, (75 FR 42085), EPA published a notice in the Federal Register announcing a settlement with TFI and certain other petitioners regarding petitions for review filed with the D.C. Circuit relating to EPA’s Greenhouse Gas Reporting Rule. In response to the notice, commenters provided comments on portions of the settlement reached with TFI. Because these comments directly relate to EPA’s proposals, we respond to the comments today. The Clean Air Task Force, Natural Resources Defense Council, and Sierra Club supported retention of the requirement for ammonia and nitric acid producers to report synthetic fertilizer production and the nitrogen content of same, and the requirement to report urea uses. [Footnote: Docket ID Number EPA-HQ-OGC-2010-0575, Comments 0014 and 0015, citing a letter from the Center for Biological Diversity, Clean Air Task Force, Environmental Defense Fund, National Wildlife Federation, Natural Resources Defense Council, Sierra Club, Union of Concerned Scientists, and WildEarth Guardians to EPA Docket ID Number EPA-HQ-OAR-2008-0508 (June 8, 2009).] According to these commenters, “EPA’s decision to require reporting of synthetic fertilizer production and nitrogen content . . . is a useful first step towards better accounting for the role of farming in the climate system.” As previously discussed, these two reporting elements have no direct correlation to “the role of farming in the climate system” because use of the elements for such a purpose assumes that 100 percent of the reported synthetic fertilizer is directly used in farming – which is not the case.

Next, the commenters state that retention of these reporting requirements makes sense relying on EPA’s first rationale for deletion of same – that “less than one-half of the total amount of nitrogen-based fertilizer used in the United States [comes from domestic production].” TFI is unclear how data accounting for far less than one-half of the synthetic fertilizer used in the United States, and the nitrogen content of same, is at all reliable to predict down-stream use of the fertilizer, especially when the reported data do not equate to fertilizer applied to the land. Finally, the commenters advocate retention of these reporting requirements given that AAPFCO may not continue to publish its data and, in any event, since the AAPFCO data are not facility-specific “this [sic] data, which is [sic] not supplier-specific and does [sic] not necessarily cover all reporting rule requirements, may soon vanish and does [sic] not, in any event, map back onto specific facilities, which EPA must track under the reporting rule mandate.” These comments, however, miss the mark.

As previously noted, the AAPFCO data, like the Greenhouse Gas Reporting Rule synthetic fertilizer and nitrogen content of same data elements, do not correlate to fertilizer applied to the land. Further, we are unclear what the commenters are referring to regarding a “reporting rule mandate” regarding “specific facilities.” To the extent commenters refer to the 2008

Consolidated Appropriations Act (H.R. 2764), nothing in that Act requires “map[ping] back to specific facilities.” Rather, the Act authorizes EPA to “develop and publish a draft rule no later than nine months after the date of enactment of this Act, and a final rule no later than 18 months after the date of the enactment of this Act, to require mandatory reporting of greenhouse gas emissions above appropriate thresholds in all sectors of the economy of the United States.” As such, we encourage EPA to move forward with the proposal to delete the requirements to report total pounds of synthetic fertilizer produced, nitrogen content of the fertilizer, and uses of urea.

Response: Without necessarily agreeing with all of the commenter’s argument, we have finalized the amendments, as proposed. Please see Section II.J of the preamble to the final rule amendments for the response to this comment.

Other Subpart G Comments

Commenter Name: William C. Herz

Commenter Affiliation: The Fertilizer Institute (TFI)

Document Control Number: EPA-HQ-OAR-2008-0508-2376.1

Comment Excerpt Number: 5

Comment: TFI encourages EPA to re-examine its reliance on the Intergovernmental Panel on Climate Change (IPCC) emission factor methodology for estimating N₂O emissions from agricultural lands, which is associated with high uncertainty. To more realistically represent greenhouse gas emissions from agricultural lands, EPA should consider use of the DAYCENT biogeochemical model. [Footnote: See for example Del Grosso et al., Global scale DAYCENT model analysis of greenhouse gas emissions and mitigation strategies for cropped soils Global and Planetary Change. Volume 67, Issues 1-2, pp. 44-50 (May 2009).] The IPCC methodology estimates nitrogen losses from croplands based solely on nitrogen inputs. In contrast, DAYCENT accounts for soil class, daily weather, historical vegetation cover, and land management practices such as crop type, fertilizer additions, and cultivation events. The DAYCENT model also allows for comparison of baseline greenhouse gas emissions and nitrogen losses for irrigated and rain-fed cropping with land management alternatives intended to mitigate greenhouse gas emissions. We agree with EPA that if the Agency was to decide in the future to add a requirement to report fertilizer production under the Greenhouse Gas Reporting Rule, or any other new requirement related to N₂O emissions from agricultural soils, the Agency should initiate a new rulemaking process.

TFI requests that any future rulemaking be preceded by a workgroup of scientists and stakeholders to determine the most appropriate methodology for determining N₂O emissions from agricultural soils, including, but not limited to, model selection, model inputs, nitrogen input data use and use of data on current best management practices and other mitigation practices.

Response: EPA thanks the commenter for the input. Part 98 does not include calculation methodologies for N₂O emission from agricultural soils and therefore this comment is outside the scope of the proposed amendments.

Commenter Name: William C. Herz

Commenter Affiliation: The Fertilizer Institute (TFI)

Document Control Number: EPA-HQ-OAR-2008-0508-2376.1

Comment Excerpt Number: 4

Comment: TFI generally agrees with EPA's concern regarding the need for better data on N₂O emissions. Nitrous oxide emissions from agricultural soils are a source of greenhouse gas emissions in the United States (approximately three percent in 2008), and the application of nitrogen-based fertilizer to soils represents some fraction of the total N₂O emissions from this source. However, TFI remains concerned that EPA is focused solely on the domestic synthetic fertilizer sector as a source of data. For example, EPA makes no mention of collecting data on the use of biosolids and organic nitrogen fertilizers for estimating N₂O emissions from agricultural fields. The proposed rule also makes no mention of soil best management practices, which peer reviewed research [Footnote: International Plant Nutrition Institute, Fertilizer Nitrogen BMPs to Limit Losses that Contribute to Global Warming (2008).] indicates can dramatically reduce N₂O emissions. In this regard, TFI and the International Plant Nutrition Institute are advancing the "4R stewardship system" as an environmental management platform based on agronomic science that involves using the right nutrient source at the right time, right rate and in the right place. The system has been endorsed by the United States Department of Agriculture (USDA), AAPFCO, specific provinces in Canada, the International Fertilizer Industry Association, Certified Crop Advisors, and others. This system has also received Land Grant university support. Several Canadian provinces have embraced the 4R system as a viable, voluntary system to pay farmers on a per acre basis to implement N₂O emissions reductions.

Response: EPA thanks the commenter for the input. Part 98 does not include calculation methodologies for N₂O emission from agricultural soils and therefore this comment is outside the scope of the proposed amendments.

7. SUBPART P - HYDROGEN PRODUCTION

Oil and Gas Flow Meter Calibration

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2008-0508-2383.1

Comment Excerpt Number: 9

Comment: Fuels and feedstocks to a hydrogen plant subject to Subpart P requirements are often the same as the fuels burned in combustion units subject to Subpart C requirements. The

monitoring and QA/QC requirements under Subparts C and P for these materials should be consistent to avoid the possibility of different requirements applying to the same stream. EPA recognized and addressed this possibility by proposing to amend Subpart P §98.164(b)(1) to require reporters to calibrate oil and gas flow meters that are used to measure liquid and gaseous feedstock volumes according to the monitoring and QA/QC requirements for the Tier 3 methodology in Subpart C §98.34(b)(1). API supports this revision. However, the carbon content and molecular weight method provisions in Subpart P were not revised to be consistent with the revisions in Subpart C. Subpart P §98.164(b)(5) lists the methods that must be used to determine carbon content and molecular weight, in contrast to the proposed revision to Subpart C §98.34(b)(4) that deletes the list of analytical methods and instead requires reporters use a method published by a consensus standards organization if such a method exists, or an industry consensus standard practice. If §98.164(b)(5) is not consistent with §98.34(b)(4), a reporter might be required to perform two different analyses for carbon content and molecular weight on the same liquid or gas stream.

API requests EPA revise the carbon content and molecular weight method provision in §98.164(b)(5) to be consistent with proposed revisions to Subpart §98.34(b)(4) such that in §98.164(b)(5) the list of analytical methods is deleted and instead reporters would be required to use a method published by a consensus standards organization if such a method exists, or an industry consensus standard practice.

Response: Please see Section II.A of the preamble for the response to this comment.

Other Subpart P Comments

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2008-0508-2383.1

Comment Excerpt Number: 45

Comment: Use of GCs to measure HHV and carbon content varies by subpart. In the August 11, 2010 proposed amendments, EPA proposed revising Subpart Y §98.254(d) consistent with our recommendation. EPA proposed adding: “Alternatively, the result of chromatographic analysis of the fuel may be used, provided that the gas chromatograph is operated, maintained, and calibrated according to the manufacturer’s instructions; and the methods used for operation, maintenance, and calibration of the gas chromatograph are document in the written Monitoring Plan for the unit under §98.3(g)(5).”

Subpart C allows the use of chromatographic analysis as long as the GC is operated, maintained and calibrated according to manufacturers’ instructions: “Use any applicable methods from the following list to determine the carbon content and molecular weight (for gaseous fuel) of the fuel. Alternatively, the results of chromatographic analysis of the fuel may be used, provided that the gas chromatograph is operated, maintained, and calibrated according to the manufacturer’s instructions.”

Subpart P references §98.34(b)(i) for flow meters, but amendments do not change requirements for carbon content and molecular weight. Subpart P specifies that an EPA-specified test method must be used to measure carbon content and molecular weight of feedstocks. The test methods list includes the following chromatography-specific methods: ASTM D1945-03; ASTM D1946-90; UOP 539-97; and GPA 2261-00. However, nowhere in Subpart P is there any language that allows the use of GCs as long as they are “operated, maintained, and calibrated according to the manufacturer’s instructions.” Rather, the rule mandates the use of an EPA-specified GC method.

Subpart X - Flare Carbon Content or HHV sampling requires that an EPA specified test method be used to measure HHV / carbon content / MW of feedstocks. The list of acceptable test methods includes GC analysis and EPA is proposing a revision to Subpart X to allow the use of modifications to the standards listed or alternative methods.

The requirements for gas chromatography should be consistent across all subparts. Accordingly, in order to enable reporters to develop a consistent approach to their sampling and analysis obligations, EPA should extend the requirements for the use of GCs under Subparts C to Subparts P, X and Y.

API requests that EPA take the following specific action: Insert the following language in each subpart: “Alternatively, the results of chromatographic analysis of the fuel may be used, provided that the gas chromatograph is operated, maintained, and calibrated according to the manufacturer’s instructions.” Note, the recent amendments (p. 332 of the pre-FR version) correct this issue in Subpart Y, but the same correction has not been made for Subparts P and X.

Response: Please see Section II.K of the preamble for the response to this comment.

8. SUBPART V - NITRIC ACID PRODUCTION

Multiple comments were received on the proposal to remove the synthetic fertilizer and total nitrogen reporting requirement in 40 CFR 98.76 (c) (Subpart G – Ammonia Manufacturing) and 40 CFR 98.226(o) in Subpart V. These were identical reporting requirements in these two subparts. Please see Section 6 of this document for the summary and response to the comments related to the removal of synthetic fertilizer reporting requirements.

9. SUBPART X: PETROCHEMICAL PRODUCTION

GHGS to Report

Commenter Name: Michael Hannan

Commenter Affiliation: Williams Olefins LLC

Document Control Number: EPA-HQ-OAR-2008-0508-2357.1

Comment Excerpt Number: 38

Comment: Revise §98.242(b) by consolidating the information contained in paragraphs (b)(1) and (b)(2) into paragraph (b) and deleting (b)(1) and (b)(2). Both paragraphs (b)(1) and (b)(2) require the reporting of CO₂, CH₄, and N₂O from the combustion of supplemental fuel, so it is unnecessary and somewhat confusing to separate the information into two paragraphs for the different compliance options.

§98.242(b) CO₂, CH₄, and N₂O combustion emissions from stationary combustion units that burn only supplemental fuel. Calculate these emissions by following the requirements of subpart C of this part (General Stationary Fuel Combustion Sources).

~~§98.242(b)(1) If you comply with §98.243(b) or (d), report these emissions from stationary combustion units that are associated with petrochemical process units and burn only supplemental fuel under subpart C of this part (General Stationary Fuel Combustion Sources) by following the requirements of subpart C.~~

~~§98.242(b)(2) If you comply with §98.243(c), report CO₂, CH₄, and N₂O combustion emissions under subpart C of this part (General Stationary Fuel Combustion Sources) by following the requirements of subpart C only for the combustion of supplemental fuel. Determine the applicable Tier in subpart C of this part (General Stationary Fuel Combustion Sources) based on the maximum rated heat input capacity of the stationary combustion source.~~

Response: No change was made as a result of this comment. This comment addresses an issue that is outside the scope of the proposed amendments published on August 11, 2010, because we did not propose amendments to the description of GHGs to report in §98.242(b).

Commenter Name: Michael Hannan

Commenter Affiliation: Williams Olefins LLC

Document Control Number: EPA-HQ-OAR-2008-0508-2357.1

Comment Excerpt Number: 39

Comment: If comment #21 [excerpt 38], above is not accepted, revise §98.242(b)(2) to eliminate the duplication of general instructions in the first sentence since they are already included in the introductory text to paragraph (b), and, delete the last sentence as it is redundant of the already referenced subpart C in the first sentence. The elimination of the duplicate language in the first sentence would make the language consistent with the preceding paragraph (b)(1).

§98.242(b)(2). If you comply with §98.243(c), report CO₂, CH₄, and N₂O combustion these emissions under subpart C of this part (General Stationary Fuel Combustion Sources) by following the requirements of subpart C only for the combustion of supplemental fuel. ~~Determine the applicable Tier in subpart C of this part (General Stationary Fuel Combustion Sources) based on the maximum rated heat input capacity of the stationary combustion source.~~

Response: No change was made as a result of this comment. This comment addresses an issue that is outside the scope of the proposed amendments published on August 11, 2010, because we did not propose amendments to the description of GHGs to report in §98.242(b).

Calculating CH₄ and N₂O emissions for Ethylene Only Options

Commenter Name: Lorraine Krupa Gershman

Commenter Affiliation: American Chemistry Council

Document Control Number: EPA-HQ-OAR-2008-0508-2368.1

Comment Excerpt Number: 8

Comment: ACC generally supports EPA's changes to this subpart. In particular, we support EPA's proposed changes to Sections 98.243(d)(2) and (d)(3) to establish provisions for small ethylene process off-gas streams. We agree that the installation of flow meters and on-line GCs or small collection taps on these ancillary gas streams is not warranted, as these streams do not significantly contribute to the overall heat input of the stationary combustion unit. EPA should clarify that these provisions can be utilized even if a flow meter is installed in a small ethylene line, since the act of collecting and analyzing samples can still be very challenging for small isolated streams.

Response: EPA disagrees with the commenter. The proposed amendments provided limited exclusions to the Tier 3 methodology for small streams. The exclusion was specifically targeted only to prevent the need to install flow meters for small streams. We did not propose changes to the carbon content measurement requirements for streams with flow meters in place. We are not persuaded by the comment that relief from such analyses is warranted because the commenter has not indicated why collecting and analyzing samples from small streams, or certain types of small streams, is any more challenging than for larger streams.

Equation X-1

Commenter Name: Michael Hannan

Commenter Affiliation: Williams Olefins LLC

Document Control Number: EPA-HQ-OAR-2008-0508-2357.1

Comment Excerpt Number: 42

Comment: §98.243(d)(5) should be changed to identify not only the flare calculation methodologies to be used but also the QA/QC requirements for measuring the flare gas flow and analyzing the flare gas composition and heat content, as follows:

§98.243(d)(5) For each flare, calculate CO₂, CH₄, and N₂O emissions using the methodology as specified in §98.253(b)(1) through (b)(3) and relevant QA/QC requirements as specified in §98.254(b) through (e).

Response: We agree with the commenter's suggested change and we modified the final rule accordingly. One of the options for flares is to measure higher heating value. Because QA/QC procedures for this measurement device are not otherwise included in subpart X, it is necessary to reference the applicable QA/QC procedures in subpart Y. In addition, §98.254(d) of subpart Y also lists methods for determining the composition of natural gas and related gas streams that are not listed in subpart X; these methods are appropriate for flare gas and need to be referenced from subpart X. Although the QA/QC procedures for flow meters should be the same in subpart X and subpart Y, for clarity we have decided to modify §98.243(d)(5) to reference §98.254(b) through (e) in subpart Y for all of the QA/QC requirements that are to be used for flares that are used with petrochemical processes.

Commenter Name: Michael Hannan

Commenter Affiliation: Williams Olefins LLC

Document Control Number: EPA-HQ-OAR-2008-0508-2357.1

Comment Excerpt Number: 46

Comment: Revise §98.243(d)(2)(ii) to allow the use of Tier 1 or 2 when a meter that does not meet the Tier 3 installation requirements is in place. (Note that the rule is currently silent with respect to Tier 3 meter installation requirements, which we believe were inadvertently deleted, and we proposed to reinstate them in other comments.) The purpose of the current exemption is to allow small units to use Tier 1 or Tier 2 subpart C equations when the otherwise required Tier 3 fuel flow meters are not in place. This recognizes that the cost of a Tier 3 meter is not justified for these small units. However, having a meter that does not meet Tier 3 installation requirements has the same practical effect as not having a meter in place. An example of such a situation is a meter that is not correctly placed in the line to allow enough upstream or downstream pipe diameters from the nearest flow disturbance to ensure uniform flow and accurate flow measurements.

§98.243(d)(2)(ii) The combustion unit has a maximum rated heat input capacity of less than 30 MMBtu/hr, and a fuel flow meter is not installed at any point in the line supplying fuel gas (that contains ethylene process off-gas) or an upstream common pipe, except if the fuel flow meter does meet the Tier 3 requirements at §98.34(b)(4). In that case, this option can be used.

Response: EPA disagrees with the commenter. The 2009 final rule required the use of Tier 3 or Tier 4 for calculating GHG emissions from all units combusting fuel gas. The proposed amendments provide additional flexibility for small streams. This flexibility was specifically targeted only to prevent the need to install flow meters for small streams. As we stated in the proposal, if a flow meter is installed, we consider the Tier 3 monitoring requirements to be reasonable and justified. Installation of a new flow meter is not required as long as the existing flow meter can be upgraded to meet the requirements of Tier 3 flow meters. Therefore, we are not making the suggested change to allow the use of Tier 1 or Tier 2 if an installed flow meter does not meet the installation requirements for Tier 3.

Commenter Name: Stancy Simpson

Commenter Affiliation: Eastman Chemical Company

Document Control Number: EPA-HQ-OAR-2008-0508-2369.1

Comment Excerpt Number: 2

Comment: Eastman requests that the EPA change the proposed wording of §98.243(d) as follows:

For each ethylene production process, calculate GHG emissions from each combustion unit combustion units that burns fuel that contains any off-gas from the ethylene process as specified in paragraphs (d)(1) through (d)(5) of this section.

The proposed introduction of "each combustion unit" appears to preclude the common pipe configuration allowed by 98.36(c)(3). Eastman submits that the common pipe reporting option is appropriate for stationary combustion units at a facility that combusts the same type of fuel and when the fuel is fed to the individual units through a common supply line or pipe. Precluding that reporting option will NOT improve the quality of the GHG emissions estimates. It will, however, introduce the following overly burdensome requirements to industry:

- Increase in calibration requirements – Multiple flow instruments would need to meet the calibration requirements of Subpart X as opposed to a single flow instrument.
- Increase in analytical requirements – Sample and analysis would be required for multiple locations as opposed to a single analysis point.
- Increase in the number of emissions calculations – Emissions calculations would need to be completed for individual units as opposed to emissions estimates for a group of combustion sources.

Response: Please see Section II.M of the preamble for the final amendments for the response to this comment.

Commenter Name: Robert Rouse

Commenter Affiliation: The Dow Chemical Company

Document Control Number: EPA-HQ-OAR-2008-0508-2366.1

Comment Excerpt Number: 9

Comment: Dow Supports EPA's Changes to the Rule for Small Ethylene Process Off-Gas Streams and Suggests Further Revisions to the Proposed Section Regarding Flow Meters.

Dow generally supports EPA's proposed changes to Sections 98.243(d)(2) and (d)(3) to establish provisions for small ethylene process off-gas streams and agrees that the installation of flow meters and on-line GC's or sample collection taps on these ancillary gas streams is not warranted as these streams do not significantly contribute to the overall heat input of the stationary combustion unit. Dow comments further that EPA should clarify that these provisions can be utilized even if a flow meter is installed in the small line since the act of collecting and analyzing samples can still be very challenging for the small isolated streams. Thus, the Tier 3 requirements remain quite burdensome. Also, existing flow meters on small lines may not be

pressure or temperature compensated. Thus, Dow proposes the following rule text change for section 98.243(d)(2)(i):

The annual average now rate of the fuel gas (that contains ethylene process off-gas) in the fuel gas line to the combustion unit, prior to any split to individual burners or ports, does not exceed 345 standard cubic feet per minute at 60°F and 14.7 pounds per square inch absolute and a flow meter is not installed at any point in the line supplying fuel gas or an upstream common pipe. Calculate the annual average now rate using company records assuming total now is evenly distributed over 525,600 minutes per year.

Response: See the response to comment EPA-HQ-OAR-2008-0508-2357.1, excerpt number 46. Regarding the statement by the commenter that existing flow meters on small lines may not be pressure or temperature compensated. In this action we have modified Part 98 to allow assumed values to be used for temperature and/or total pressure at the flow meter location, based on measurements of these parameters at a remote location (or locations) if certain conditions are met. Please see section II.F of the preamble to the final rule amendments for additional discussion of these conditions. We would emphasize that both the option of using assumed values for temperature and/or total pressures at the flow meter location, as well as the opportunity to use Tier 1 or Tier 2 for small streams under certain circumstances, reduce the burden of the 2009 final rule. Given this additional flexibility allowed in the August 11, 2010 amendments we have concluded that the burden for temperature and pressure compensated flow meters is significant enough to warrant modifying the requirement to use Tier 3 if flow meters are in place.

Monitoring and QA/QC Requirements

Commenter Name: Michael Hannan

Commenter Affiliation: Williams Olefins LLC

Document Control Number: EPA-HQ-OAR-2008-0508-2357.1

Comment Excerpt Number: 43

Comment: Revise §98.244(b)(2) to address meter installation requirements in addition to the already specified operation and maintenance requirements. This is important because the installation standards specify, for example, the minimum distance to the nearest flow disturbance, which is important for obtaining accurate flow data. Also, expand the installation, operation, and maintenance requirements to include, in addition to manufacturer's recommended procedures, methods published by a consensus-based standards organization or industry consensus standard practice. Lastly, allow the calibration and recalibration of feedstock and product flow meters by a consensus-based standards organization method in addition to the industry consensus standard method or manufacturer recommended method. These changes are all consistent with the fuel meter requirements in subpart C (General Stationary Fuel Combustion Sources).

§98.244(b)(2) Install, Operate and maintain all flow meters used for gas and liquid feedstocks and products according to one of the following methods manufacturer's

recommended procedures. You may use the manufacturer's recommended procedures, a method published by a consensus-based standards organization, or industry consensus standard practice. You must calibrate each of these flow meters according to one of the following. You may use a method published by a consensus-based standard organization if such a method exists, an industry consensus standard method, or methods specified by the flow meter manufacturer. Consensus-based standards organizations include, but are not limited to, the following: ASTM International, the American National Standards Institute (ANSI), the American Gas Association (AGA), the American Society of Mechanical Engineers (ASME), and the American Petroleum Institute (API). Each flow meter must meet the applicable accuracy specification in §98.3(i), except as otherwise specified in §98.3(i)(4) through (i)(6). You must recalibrate each flow meter according to one of the following frequencies. You may recalibrate either biennially, at the minimum frequency specified by the manufacturer, at the interval specified by the consensus-based standards organization method, or at the interval specified by the industry consensus standard practice used.

Response: After careful consideration, we have decided not to make the suggested change to 40 CFR 98.244(b)(2) because we did not want to broaden an “industry consensus standard method” to an “industry consensus standard practice”. It is our interpretation that a “method” is a documented process or procedure to be followed whereas a “practice” may be more general in nature. (We note that we do, however, interpret a method published by a consensus-based standards organization to include an “industry consensus standard method.” The commenter did not provide sufficient justification for why the existing methods are not sufficient or why the allowable methods should be expanded to include “standard practices”. We have also decided not to amend §98.244(b)(2) to add meter installation requirements because we have concluded that a flow meter can not be operated according to the requirements of the rule without being installed according to those requirements as well. We therefore interpret “operate” to include “install”.

Commenter Name: Michael Hannan

Commenter Affiliation: Williams Olefins LLC

Document Control Number: EPA-HQ-OAR-2008-0508-2357.1

Comment Excerpt Number: 47

Comment: Revise §98.244(b)(4) and (Subpart Y) §98.254(d) and (e) to add flexibility to the sampling and analysis requirements. EPA added flexibility to the fuel sampling and analysis requirements in subpart C (General Stationary Fuel Combustion Sources) by eliminating the list of specific methods and instead allowing a broader array of methods. In the preamble to the proposed changes EPA recognized that:

Although we attempted to assemble a comprehensive list of methods and provide appropriate alternatives, it is possible that other valid methods from these organizations and practices have been overlooked, or that in some cases, industry consensus standard methods may be more appropriate than the methods listed.

To be fair, equitable, and create a level-playing field for various industries (e.g., utilities, petrochemical producers, and petroleum refineries), this flexibility should also be afforded to the feedstock and product sampling and analysis requirements in Subpart X (Petrochemical Production) and gas (including flare gas) sampling and analysis requirements in Subpart Y (Petroleum Refineries). Additionally, allow the use of analyses conducted by the purchaser of a product. There is no reason such analyses should be treated any differently from those supplied by a fuel or feedstock supplier.

[The commenter provided suggested amendatory language for §98.244(b)(4) and §98.254(d) and (e) of Subpart Y, if the recommended approach were adopted. The commenter also noted that adopting the recommended changes would also necessitate changes to §98.7 and provided suggested amendatory language for this section. The suggested language is not reproduced in this document, but can be found in the commenter's letter in the docket for this rule-making.]

Response: We did not propose to amend §98.244(b)(4) in subpart X or §98.254(d) and (e) in Subpart Y to provide the same fuel sampling and analysis options as proposed for Subpart C. We are specifically maintaining the specified lists of acceptable methods in subparts X and Y because: 1) we identified these as the most appropriate methods to use for these gas streams; and 2) providing direct methods makes it easier for reporters to identify appropriate methods. We are providing additional flexibility regarding use of other gas chromatographic methods provided the chromatograph is operated, maintained, and calibrated according to the manufacturer's instructions and the methods are documented in the facility's Monitoring Plan. These revisions provide the flexibility requested by the commenter while still providing guidance and assistance to reporters that would like to know the methods most likely to be appropriate for these gas streams. Please see Section II.M of the preamble to the final rule amendments for additional information on this comment.

The commenter requests that the rule allow petrochemical producers to use the results of analyses conducted by purchasers of their products. We have not incorporated this suggested change in the final amendments because we did not propose amendments to the provisions specifying who may conduct analyses. Therefore, this comment is beyond the scope of the proposed amendments published on August 11, 2010.

The commenter also suggested editorial changes to how methods in the appendices to 40 CFR part 60 are referenced. We have not made the suggested editorial changes. The paragraphs containing those methods were not included in the proposed amendments published on August 11, 2010.

Commenter Name: Larry Scheinpflug

Commenter Affiliation: Columbian Chemicals Company

Document Control Number: EPA-HQ-OAR-2008-0508-2363

Comment Excerpt Number: 1

Comment: We would like to add the following comment under §98.243(c)(3) "Calculating GHG emissions." To the statement "Collect a sample of each feedstock and product at least

once per month and determine the carbon content of each sample according to the procedures in 98.244(b)(4).” Add, “However, if multiple deliveries of a particular type of fuel or feedstock oil used in the carbon black manufacturing process are received from the same supply source in a given calendar month, the deliveries for that month are considered, collectively, to comprise a fuel lot, requiring only one representative sample.”

Response: Please see Section II.M of the preamble to the final rule amendments for the response to this comment.

Commenter Name: Larry Scheinpflug
Commenter Affiliation: Columbian Chemicals Company
Document Control Number: EPA-HQ-OAR-2008-0508-2363
Comment Excerpt Number: 2

Comment: We agree with the proposed change under §98.244(b)(4), Monitoring and QA/QC requirements, paragraph (xii), “An industry standard practice for carbon black feedstock oils and carbon black products, effective as of January 1, 2010.”

Response: EPA thanks the commenter for the input. We have finalized the amendments referenced by the commenter, as proposed.

Commenter Name: Larry Scheinpflug
Commenter Affiliation: Columbian Chemicals Company
Document Control Number: EPA-HQ-OAR-2008-0508-2363
Comment Excerpt Number: 3

Comment: We would like to add the following under §98.244(b)(4), Monitoring and QA/QC. Add paragraph (xiv): “ASTM D7633 Standard test method for Carbon Black – Carbon Content it is effective as of January 1, 2010.” Please note this method was reviewed, accepted and approved by an International group within ASTM on May 15, 2010. You may visit their website at the following for further information <http://www.astm.org/Standards/D7633.htm>.

Response: Please see section II.M of the preamble to the final rule amendments for the response to this comment.

Commenter Name: Larry Scheinpflug
Commenter Affiliation: Columbian Chemicals Company
Document Control Number: EPA-HQ-OAR-2008-0508-2363
Comment Excerpt Number: 4

Comment: We would like to add the following under §98.244(b)(4), Monitoring and QA/QC requirements. Add paragraph (xv), “As of 9/23/10 ASTM is currently working on a Standard Test Method for Carbon Content in Carbon Black Feedstock Oils under work item number

WK27667. Once this ASTM method is approved and assigned an official number it is effective as of January 1, 2010.”

Response: Please see section II.M of the preamble to the final rule amendments for the response to this comment.

Commenter Name: Stancy Simpson

Commenter Affiliation: Eastman Chemical Company

Document Control Number: EPA-HQ-OAR-2008-0508-2369.1

Comment Excerpt Number: 1

Comment: EPA solicited comments on whether the proposal to allow modifications of existing analytical methods for determining carbon content and molecular weight is warranted. Eastman agrees with the EPA allowance for alternatives for carbon content (CC) and molecular weight (MW).

In particular, Eastman believes that the rule revisions proposed in §98.244(b)(4)(xiii) will provide for more accurate GHG emissions reporting. That revision specifically allows modifications of existing analytical methods or other analytical methods that are applicable to your process provided that the methods listed in 98.244(b)(4)(i) through 98.244(b)(4)(xii) are not appropriate because the relevant compounds cannot be detected, the quality control requirements are not technically feasible, or use of the method would be unsafe, effective as of January 1, 2010.

An example of the need for this revision is analysis of a water saturated carbon dioxide stream that Eastman sends to a toll converter. This stream meets the Subpart X definition of a "product" stream and, thus, must be analyzed for CC and MW. In the current rule, §98.244(b)(4) presents standard methods for determining the CC and MW. In particular, Eastman may use ASTM 1945. However, this product stream is water saturated and Method 1945 prescribes no methodology for adjusting CC and MW for stream water content. Using Method 1945 in this context will lead to under-reporting of greenhouse gas (GHG) emissions. Therefore, the proposed allowance for "Modifications of existing analytical methods" would allow CC and MW data to be adjusted for stream water content and yield more valid results and emissions estimates.

Eastman believes, however, that EPA should provide even more flexibility in certain circumstances. Specifically, Eastman recommends that EPA's revision of §98.244(b)(4)(xiii) be revised as follows:

Modifications of existing analytical methods or other ~~analytical~~ methods that are applicable to your process provided that the methods listed in 98.244(b)(4)(i) through 98.244(b)(4)(xii) are not appropriate because the relevant compounds cannot be detected, the quality control requirements are not technically feasible, or use of the method would be unsafe, effective as of January 1, 2010.

Eastman is particularly interested in the revision to § 98.244(b)(4)(xiii) since it would very clearly address an issue Eastman has previously brought to the EPA's attention. More specifically, on January 26, 2010, Eastman notified EPA that the rule-prescribed sampling and analysis of the ethylene oxide/water mixture from Eastman's two Ethylene Oxide (EO) plants presents a significant personnel safety hazard. In that correspondence Eastman fully described its safety concerns. The solution Eastman proposed was the use of densitometers in lieu of sampling and analyzing the EO/water streams.

Eastman's proposed further amendment to § 98.244(b)(4)(xiii) would allow it to use densitometers in lieu of having to sample and analyze the ethylene oxide/water mixture from its two EO plants. In the absence of this proposed change, Eastman is concerned that some may interpret EPA's use of the term "analytical method" to exclude the use of densitometers. Therefore, Eastman strongly urges the EPA to provide this additional needed flexibility.

Response: Please see section II.M of the preamble to the final rule amendments for the response to this comment. .

Commenter Name: Paul Mikesell

Commenter Affiliation: Cytec Industries

Document Control Number: EPA-HQ-OAR-2008-0508-2384.1

Comment Excerpt Number: 1

Comment: Cytec Industries (Cytec) agrees with other owners and operators that EPA should not limit carbon content and composition to only the analysis methods currently listed in the Mandatory Reporting Rule. The current GC methods are limited to specific products or materials and ignore polymers and isomers and are inappropriate for certain analytes.

Cytec has an operating unit subject to the GHG MRR Subpart X requirements, which require mass balance calculation methodology be performed. In doing so, we consider carbon in versus carbon out in order to estimate GHG emissions. The carbon out includes waste streams where carbon content analysis is necessary and the listed GHG MRR analysis are not appropriate. Prior to the GHG MRR, Cytec used TOC analysis per EPA Method 9060A of SW846 for analysis of waste streams for internal use. Being that this method is not included in the GHG MRR, we have been simultaneously using EPA Method 8015, included in the GHG MRR per 98.244(b)(4) and the EPA TOC analysis per Method 9060A, gathering data to substantiate our use of an alternate analysis in order to submit a request to EPA. Analysis of waste streams, at an applicable GHG MRR Subpart X operating unit, demonstrate that EPA Method 9060A in all cases revealed a greater carbon content value when compared to the inappropriate GHG MRR Method 8015 results. Results vary depending on the streams sampled, but TOC analysis using EPA Method 9060A results range from < 1% to 99.5% greater carbon content values. As stated above, the GC methods ignore polymers and isomers, to which EPA's TOC Method 9060A does not. Also, the cost and time associated with performing the GHG MRR Method 8015 are substantially greater than performing EPA's TOC Method 9060A.

An additional analysis performed by Cytec's Lab uses an internal modified method for analysis of acetonitrile product for Certificates of Analysis (COA's) when product is sold. Being that this Cytec modified method would not be included in the GHG MRR, when acetonitrile product is sold, analysis will be performed using the GHG MRR listed 8015 Method per §98.244(b)(4) and the Cytec modified method analysis simultaneously, while gathering data to substantiate our use of an alternate analysis in order to submit a request for approval to EPA.

Cytec appreciates the ability to submit comments on this proposed regulation and is confident that EPA will agree to allow for alternate carbon content analysis methods such as EPA's Method 9060A for TOC, as well as the possibility of using Cytec's internal modified method. Again, EPA's Method 9060A for TOC more accurately reflects the total carbon content of the streams where monitoring is required, is far less time consuming and less expensive to conduct, while achieving more accurate results.

Response: Please see section II.M of the preamble to the final rule amendments for the response to this comment.

Commenter Name: Robert Rouse

Commenter Affiliation: The Dow Chemical Company

Document Control Number: EPA-HQ-OAR-2008-0508-2366.1

Comment Excerpt Number: 10

Comment: EPA should add an option to §98.244(b)(4) which allows the use of an on-line mass spectrometer to determine the carbon content and molecular weight of feedstock or product streams. The rule should require that the instrument be operated, maintained, and calibrated according to the manufacturer's instructions. Technical details regarding an on-line mass spectrometer in use at one of our sites are included as an attachment (Attachment 1).

[See Attachment 1. Technical Details for On-line Mass Spectrometer in use at Dow's St Charles, Louisiana Site. Copyrighted page/s removed. Copyrighted material is not available in Regulations.gov since it may not be reproduced without consent of the copyright holder. Contact the EPA Docket Center's Public Reading Room to view or receive a copy of this document. Requests for copies may be made as follows: In person/writing: Environmental Protection Agency, Docket Center 1301 Constitution Ave NW, 2822T, Room 3334 Washington, DC. 20004, Telephone: 202-566-1744, Fax: 202-566- 9744 Email: docket-customerservice@epa.gov]

In addition, Dow generally supports the proposed addition of paragraph (xiii), but also suggests that the rule allow for modifications of existing analytical methods or the use of other analytical methods for reasons beyond those listed (i.e., relevant compounds cannot be detected, the quality control requirements are not technically feasible, or use of the method would be unsafe). Cases exist where an owner/operator has already installed an instrument which is capable of making the required measurements, but the analytical approach is not currently listed in Section 98.244(b)(ixii). These alternative analytical instruments should also be allowed if the owner/operator can generally demonstrate that these method(s) can accurately measure the carbon content and composition or molecular weight of the feedstock or product stream.

Response: Please see section II.M of the preamble to the final rule amendments for the response to this comment.

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2008-0508-2383.1

Comment Excerpt Number: 10

Comment: EPA is proposing a new paragraph §98.244(b)(4)(xiii) to allow petrochemical facilities to use modifications to the analytical methods listed in §98.244(b)(4) or other applicable analytical methods provided that the methods listed in §98.244(b)(4)(i) through (xii) are not appropriate because the relevant compounds cannot be detected, the quality control requirements are not technically feasible, or the use of the method would be unsafe, effective as of January 1, 2010. EPA is proposing in 40 CFR 98.246(a)(11) that if an alternative method is used, facilities would include in the annual report the name or title of the method used, and the first time it is used, a copy of the method and an explanation of why the use of the alternative method is necessary. EPA solicited comment on whether the flexibility provided by this option is needed.

API supports this proposed revision and the flexibility it affords to reporters to use alternate methods that are better suited for a given process.

Response: EPA thanks the commenter for the input. We have finalized the proposed provisions to allow for modifications of existing analytical methods under certain circumstances.

Data Reporting Requirements

Commenter Name: Michael Hannan

Commenter Affiliation: Williams Olefins LLC

Document Control Number: EPA-HQ-OAR-2008-0508-2357.1

Comment Excerpt Number: 44

Comment: Revise §98.246(a)(4) to directly report the MVC value used instead of the temperature at which the volumes were measured. The purpose of reporting the temperature is to be able to verify that the correct MVC value was used so direct reporting of the MVC value used would make reporting the temperature unnecessary. This would also make this paragraph consistent with the analogous data reporting requirements for flares at §98.256(e) and therefore promote consistency throughout the rule.

§98.246(a)(4) Each of the monthly volume, mass, and carbon content values used in Equations X-1 through X-3 of this subpart (i.e., the directly measured values, substitute values, or the calculated values based on other measured data such as tank levels or gas composition) and the

molecular weights and molar volume conversion factor used in Equation X-1 of this subpart, and the temperature (in °F) at which the gaseous feedstock and product volumes used in Equation X-1 of this subpart were determined.

Response: We considered requiring reporting of just the MVC value. However, we concluded that if the temperature is reported, it will enhance our ability to conduct verification on the reported emissions.

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2008-0508-2383.1

Comment Excerpt Number: 11

Comment: EPA is proposing in §98.246(a)(11) that if an alternative standard is used, the report must provide a copy of the standard. It is unclear how the electronic reporting system will be set up to allow the submittal of such documents.

Response: The electronic reporting system will allow reporters to attach documents to an annual report submittal.

Other Subpart X Comments

Commenter Name: Michael Hannan

Commenter Affiliation: Williams Olefins LLC

Document Control Number: EPA-HQ-OAR-2008-0508-2357.1

Comment Excerpt Number: 40

Comment: Delete the second sentence of §98.243(c)(3) because it is duplicative of the procedures in §98.244(b)(4). .

~~“Alternatively, you may use the results of analyses conducted by a fuel or feedstock supplier provided the sampling and analysis are conducted at least once per month using any of the procedures specified in §98.244(b)(4).”~~

If this comment is not accepted, revise this sentence to allow the use of analyses conducted by the purchaser of a product

Alternatively, you may use the results of analyses conducted by a fuel or feedstock supplier, **or product purchaser**, provided the sampling and analysis are conducted at least once per month using any of the procedures specified in §98.244(b)(4).

There is no reason such analyses should be treated any differently from those supplied by a fuel or feedstock supplier.

Response: Response: Although it is repetitive, we think it is helpful to clarify in §98.243(c)(3) that an owner or operator has the option of conducting the sampling and analysis in-house or to use the results provided by a feedstock supplier. We also decided not to adopt the commenter's alternative suggestion to add "or product purchaser" to this paragraph. Such a change is outside the scope of this final rulemaking effort because we did not propose changes to 98.243(c)(3).

Commenter Name: Robert Rouse

Commenter Affiliation: The Dow Chemical Company

Document Control Number: EPA-HQ-OAR-2008-0508-2366.1

Comment Excerpt Number: 7

Comment: EPA should establish in §98.243(c), "Mass Balance for each petrochemical process unit," that small quantities of additives are excluded from the material balance calculations for the following reasons:

The annual quantity of these additives is typically so small that they don't have a significant impact on the overall material balance calculation. For example, a process may use < 100,000 lbs/yr of a liquid additive, but produce 500,000,000 lbs/yr of a petrochemical product, thus the amount of liquid additive is < 0.02% of the product stream, which is far less than required accuracy (+5%) of feedstock flow meters and product stream flow meters. Thus, the contribution of the additive carbon material will be of little consequence to the overall material balance.

Obtaining the required carbon content information for each liquid additive can also present challenges since sometimes the composition of the liquid is proprietary information that can only be obtained from an outside vendor. In some cases, vendors are refusing to provide this level of information regarding their additives which then requires time consuming and costly sampling for these small streams. Also, in some cases, the owner/operator is not allowed per contract to analyze the vendor's raw materials.

Determining the exact flowrate for these small additive streams can also be problematic. At a minimum, EPA should provide an option in the rule that allows the owner/operator to count the number of fixed volume containers that are used in a given month to determine monthly usage volume.

If EPA decides not to exclude these small additives, the final rule should include a provision that allows the owner/operator to use default carbon content and flowrate values based on process knowledge, engineering calculations, and other readily available information to ease the reporting burden for these small streams.

Response: No rule change has been made as a result of this comment. This comment addresses an issue that is outside the scope of the current rulemaking because we did not propose amendments to the types of streams for which measurement is required when using the mass balance option in §98.243(c).

Commenter Name: Robert Rouse
Commenter Affiliation: The Dow Chemical Company
Document Control Number: EPA-HQ-OAR-2008-0508-2366.1
Comment Excerpt Number: 8

Comment: EPA should clarify that supplemental gas streams that are routed to petrochemical processes that contain trace quantities of hydrocarbons (i.e., up to 0.5 wt% hydrocarbons) are excluded from the definition of feedstock. This would alleviate confusion over which types of miscellaneous gas streams have to be considered as feedstocks in situations where a gas stream is routed to petrochemical process just for efficiency purposes. In many cases, these types of gas streams are generated by a non-covered process and are routed to the Subpart X petrochemical process to recover process materials. The small amount of additional carbon present in these supplemental gas streams does not impact the quality of the material balance for the Subpart X process and should not be included since the origin of the carbon comes from a non-covered process.

Response: Please see the response to comment EPA-HQ-OAR-2008-0508-2366.1, excerpt 7, for the response to this comment.

10. SUBPART Y- PETROLEUM REFINERIES

GHGs to report

Commenter Name: Karin Ritter
Commenter Affiliation: American Petroleum Institute (API)
Document Control Number: EPA-HQ-OAR-2008-0508-2383.1
Comment Excerpt Number: 13

Comment: EPA incorporated API's proposed changes to some fuel gas provisions, per the settlement agreement to the Request for Reconsideration filed by API and NPRA. [Note: EPA's notice announced six proposed settlement agreements to address six separate petitions for review of the MRR. See 75 FR 42,085 (July 20, 2010). API and NPRA's comments were directed solely at the Settlement Agreement proposed to resolve litigation in American Petroleum Institute et. al. v. EPA (D.C. Cir. No. 09-1328).] These changes are now reflected in the proposed revisions to §98.252(a). However, upon further review, API members have identified gas streams in which Tier 3 requirements are imposed due to the amended language. These are streams where the associated weekly sampling poses a significant safety issue as well as significant difficulty in sampling streams that were not previously accessed for sampling. These small flow streams would otherwise fit the requirements for the use of Tier 1 or Tier 2 methodologies if it were not for the fact that they are equipped with flow meters. These streams are not what industry would define as "refinery fuel gas" but would fall under the realm of "fuel gas" as is written into the definition under the rule. These can include streams that are process off-gas or vent gases with

properties much different than traditional “refinery fuel gas” streams and are not part of the refinery’s fuel gas system.

As stated previously, these off-gas streams may not currently be sampled, and only due to the changed rule language, these streams with an existing flow meter must now be sampled weekly. Many of these streams are difficult to sample (for example, because of low pressure) or may present hazardous sampling conditions. Examples of safety issues associated with sampling these streams include toxicity of the stream, potentially high temperature conditions, or flammability and explosion potential. In these situations, the added rigor associated with Tier 3 requirements and the additional expense to safely conduct the weekly sampling are not justified for the increased safety risk and overall minuscule contribution of emissions (on the order of 0.1% of a refinery’s total greenhouse gas emissions as estimated by some member companies). EPA should not impose high risk sampling requirements for a negligible improvement in accuracy.

API requests that §98.252(a)(1)(ii) and §98.252(a)(2)(ii) be further amended to exclude such small flow or hazardous fluid streams that may have a meter but are not currently being sampled per Tier 3 requirements, and allow the use Tier 1 or Tier 2 calculation methodologies for these streams if they meet the other parameters of the regulatory language. Please see below for suggested wording (see the edits in square brackets):

(1) The annual average fuel gas flow rate in the fuel gas line to the combustion unit, prior to any split to individual burners or ports, does not exceed 345 standard cubic feet per minute at 60°F and 14.7 pounds per square inch absolute and either of the conditions in paragraph (a)(1)(i) or (ii) of this section exist. Calculate the annual average flow rate using company records assuming total flow is evenly distributed over 525,600 minutes per year.

(i) A flow meter is not installed at any point in the line supplying fuel gas or an upstream common pipe.

(ii) The fuel gas line contains vapors from loading or unloading, waste or wastewater handling, [off-gas or vent gas not part of the refinery fuel gas system,] and remediation activities that are combusted in a thermal oxidizer or thermal incinerator.

(2) The combustion unit has a maximum rated heat input capacity of less than 30 MMBtu/hr and either of the following conditions exist:

(i) A flow meter is not installed at any point in the line supplying fuel gas or an upstream common pipe; or

(ii) The fuel gas line contains vapors from loading or unloading, waste or wastewater handling, [off-gas or vent gas not part of the refinery fuel gas system,] and remediation activities that are combusted in a thermal oxidizer or thermal incinerator.

Response: Please see Section II.N of the preamble to the final rule amendments for the response to this comment.

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2008-0508-2383.1

Comment Excerpt Number: 32

Comment: API supports the clarification of §98.252(i) – Clarified hydrogen produced from catalytic reforming units is not subject to Subpart P.

Response: EPA thanks the commenter for the input. We have finalized the amendments as proposed.

Reporting Emissions From Flares

Commenter Name: Michael Hannan

Commenter Affiliation: Williams Olefins LLC

Document Control Number: EPA-HQ-OAR-2008-0508-2357.1

Comment Excerpt Number: 50

Comment: Revise §98.253(b)(1)(ii)(A) and §98.253(b)(1)(ii)(B) to allow facilities that routinely measure the carbon content and/or heat value of the flare gas an option to separately measure or estimate these parameters for startup, shutdown and malfunction events exceeding 500,000 scf/day and use these values to calculate flare emissions separately for these events. The flare calculations at subpart Y are separated into two basic categories for facilities that do and do not measure the carbon content and/or heat value of the flare gas at least weekly. Facilities that do not measure these parameters must measure or estimate the heat content of the fuel gas during periods of normal operation and use those values to calculate flare emissions. They also must separately estimate the carbon content of the flare gas during periods of start-up, shutdown, or malfunction when the flared gas volume exceeds 500,000 scf/day and use that value to calculate emissions from these events. Facilities that do measure the carbon content and/or heat value of the flare gas must use the results of these analyses to calculate flare emissions for both normal operations and emission events. However, these samples may not be representative of the flare gas during a start-up, shutdown, or malfunction event, as the characteristics of the gas during these events can vary markedly from routine operations. Providing an option to facilities that routinely measure the carbon content and/or heat value of the flare gas to use an estimate of these parameters that are specific to the start-up, shutdown, or malfunction event would result in more accurate emission calculations.

[The commenter provided suggested amendatory language for §98.253(b)(1)(ii)(A) and §98.253(b)(1)(ii)(B). The commenter also noted that adopting the recommended changes would also necessitate changes to the recordkeeping requirements at §98.256(e)(6) through (e)(8), and provided suggested amendatory language for those sections. The suggested language is not reproduced in this document, but can be found in the commenter letter in the docket for this rule-making.]

Response: We expect that facilities that routinely measure the carbon content or heat content of the flare gas will directly include the effects of any startup, shutdown or malfunction (SSM) event on the reported flow rates and carbon content (or heat content) of the flare gas during that

measurement period. Nothing in the rule prevents the reporter from making more frequent measurements. That is, we consider that the rule adequately accommodates the commenter's request without the need for additional amendments. While the emissions will not be characterized separately as emissions from "normal operations" and emissions from an "event," the values used in Equations Y-1a, Y-1b, or Y-2 should fully characterize the total emissions from the flare. Consequently, we determined that the suggested amendments are unnecessary.

Sulfur Recovery: Sour Gas Sent Offsite

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2008-0508-2383.1

Comment Excerpt Number: 34

Comment: The revised §98.253(f) expanded provisions to include reporting for sour gas sent off site for sulfur recovery and for non-Claus sulfur recovery plants. API does not support adding reporting burden or the requirement for refiners to have to report emissions from off-site, non-operated processes.

Response: The amendments proposed did not add any additional reporting burden. Per §98.252(c) of the final rule promulgated in October 30, 2009, which describes the GHGs to be reported, emissions from off-site sulfur recovery units were already required to be reported. This section (§98.252(c)) specifically states (per the October 30, 2009 final rule) that the calculation methodologies listed in §98.253(f) must be followed for calculating CO₂ emissions from sour gas sent off site for sulfur recovery operations. Similarly, the October 30, 2009, final rule included reporting requirements in §98.256(h) for "sulfur recovery plants and for emissions from sour gas sent off-site for sulfur recovery." The amendments proposed to §98.253(f), which describe how GHG emissions are to be calculated, adding the phrase "and for sour gas sent off-site for sulfur recovery" are for clarification purposes only; no new reporting burden was added.

Regarding non-Claus sulfur recovery plants, these plants were already included in the reporting requirements under §§98.252(d) and 98.256(h). We received questions regarding how to apply the calculation methodologies to non-Claus sulfur recovery plants, which we proposed to address in these amendments. We consider the proposed amendments to provide more reasonable methodologies for non-Claus sulfur recovery plants, and are finalizing these amendments as proposed.

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2008-0508-2383.1

Comment Excerpt Number: 47

Comment: In §98.253(f)(4), Equation Y-12 is to be used for calculating CO₂ emissions from sulfur recovery units. However, the equation provides a default carbon content of 0.20 mole fraction in the sour gas feed to the sulfur recovery plant. This default carbon content seems very high and is not supported by any references. The methodology presented in the API Compendium has no default carbon content; it is assumed that each site will develop their own factor based on typical operating conditions. API requests to remove the default carbon content.

Response: Reporters are allowed to develop their own site-specific carbon content and use this value in Equation Y-12. However, based on comments we received on the original April 10, 2009 proposal, many reporters desired to have simple default parameters to use for “smaller” emission sources. We see no benefit to removing this default value, and if we did remove it the monitoring requirements of the rule would increase because facilities would be required to measure the carbon content of this stream rather than rely on the default value. Therefore, we are not removing this default parameter.

CO₂ Emissions From Asphalt Blowing

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2008-0508-2383.1

Comment Excerpt Number: 48

Comment: In §98.253(h)(1), Equations Y-14 and Y-15 provide default emission factors of 1100 tonnes CO₂/MMbbl asphalt and 580 tonnes CH₄/MMbbl for uncontrolled asphalt blowing. The 2009 API Compendium presents in Table 5-7 on page 5-34 other default factors for uncontrolled emission. The emission factors presented are 1010 tonnes CO₂/MMbbl and 555 tonnes CH₄/MMbbl (converted from bbl basis to MMbbl basis).

API requests to reconcile values with the API Compendium values since these values were derived using data provided by EPA as reference to AP-42.

Response: We derived the default emission factors of 1100 tonnes CO₂/MMbbl asphalt and 580 tonnes CH₄/MMbbl for uncontrolled asphalt blowing based on the data presented in the 2004 API Compendium, which directly reports the concentrations, AP-42 emission factors, and the assumptions used. The 2009 API Compendium appears to cite the same data sources, but only presents the emission factors. We cannot derive the values reported in the 2009 API Compendium from the concentration data and AP-42 emission factor. We do note that the values suggested in the 2009 API Compendium are not significantly different from those required for use in Equations Y-14 and Y-15, but the 2009 API Compendium values are reported without sufficient background data to understand their derivation. Consequently, as we understand the basis of the values required in the GHG reporting rule and have been provided no direct evidence that our original calculations (which are based on the data more fully presented in the 2004 API Compendium) are incorrect, we are not revising these emission factors in the final amendments

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2008-0508-2383.1

Comment Excerpt Number: 49

Comment: In §98.253(h)(2), Equation Y-16 provides the CO₂ emissions estimate for asphalt blowing controlled by a flare or thermal oxidizer based on a material balance that uses the carbon content of the controlled asphalt blown stream. A default value of 2750 tonnes carbon/MMbbl asphalt is provided. In comparison, the API Compendium in Equation 5-13 on page 5-35 also uses a material balance approach for estimating the controlled asphalt blowing CO₂ emissions and accounts for the CO₂ already in the stream plus the conversion of CH₄ to CO₂ from the controlled combustion. API requests to allow the use of the more comprehensive mass balance method using Equation 5-13 on page 5-35 of the 2009 edition of the API Compendium, process.

Response: We disagree that Equation 5-13 of the API Compendium is a more comprehensive approach to estimating CO₂ emissions from asphalt blowing controlled by a flare or thermal oxidizer. The equation in the 2009 API Compendium does not take into account ethane, propane, butane, and heavier organic compounds that exist in the asphalt blowing stream and that will be converted to CO₂ in the control device. These other compounds, as seen in the data provided in the 2004 Compendium, represent a significant mass of carbon in the asphalt stream. While we agree that there is a slight low bias in Equation Y-16 as the 0.98 factor arguably should not be applied to the CO₂ carbon, we find that Equation Y-16 is much more appropriate than Equation 5-13 of the 2009 Compendium. We do agree that the 0.98 factor should not apply to the CO₂ pre-existing in the vent stream, but we are also concerned with increasing the measurement data requirements (for those using facility-specific carbon emission factors). Therefore, we proposed to retain Equation Y-16 (re-numbering it as Y-16a) and also included a new Equation Y-16b that does not apply the 0.98 conversion factor to the CO₂ pre-existing in the vent gas prior to the control device. These provisions are being finalized as proposed.

Other Equations

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2008-0508-2383.1

Comment Excerpt Number: 35

Comment: API supports the revision of Equation Y-19 – Clarified the equation for process vent emissions allowing the use of measurement data, process knowledge, or engineering estimates to determine the volumetric flow rate and mole fraction of GHG.

Response: EPA thanks the commenter for the input. We have finalized the amendment, as proposed.

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2008-0508-2383.1

Comment Excerpt Number: 50

Comment: In §98.253(i)(1), Equation Y-18 fails to correct the gaseous emissions for temperature. The equation does contain the pressure correction but left out the corresponding temperature correction. Since the equation is based on the actual volume vented from the coke vessel, both the pressure and temperature of the vessel should be corrected with the applicable molar volume correction factor used for the applicable conditions. If the degassing occurs above standard temperature, the current Equation Y-18, as provided in the final rule, would overestimate emissions.

The amended equation Y-18 should read:

$$\text{CH}_4 = (\text{Current Equation Y-18}) * [(T_{\text{std}} + 460) / (T_{\text{steam}} + 460)]$$

Where,

T_{std} = temperature of gas (degrees Rankine) at standard conditions, and

T_{steam} = temperature of the gas (degrees Rankine) in the delayed coking vessel

Equation Y-18 should be corrected to include the applicable gas law temperature correction and the appropriate molar volume correction factor that is applicable for the standard conditions used.

Response: We disagree that Equation Y-18 will underestimate the emissions from the delayed coking unit. While we acknowledge that the equation does not have the ideal gas law temperature correction, it also does not account for additional steam generated as the pressure is lowered. We originally developed this equation based on correlations with actual flows from this vent. In the 2009 proposal, we also did not include a correction factor for the void fraction. We added this correction factor in the 2009 final rule, but this approach tended to cause Equation Y-18 to slightly underestimate the actual emissions from the test data. Including the temperature correction factor requested would further bias the estimates from Equation Y-18 low. Actually, at higher depressurization temperatures, more steam is generated during the venting process, thereby increasing the flow from the system rather than lowering the flow as the “correction” suggested by API would yield. Thus, we intentionally omitted the temperature correction factor as a means to account for the added flow caused by steam generation as the pressure of the system is lowered and to provide a better correlation of the available data. We considered including a flow term to account for the additional gas generated from the system, but this would significantly increase the complexity of the equation and would require numerous additional monitoring variables. Consequently, we are not revising Equation Y-18 at this time.

We note that direct measurements of the emissions from this vent are allowed within the existing provisions of the rule if a more accurate estimate of these emissions is desired by the reporter.

Calculating GHG Emissions

Commenter Name: Michael Hannan

Commenter Affiliation: Williams Olefins LLC

Document Control Number: EPA-HQ-OAR-2008-0508-2357.1

Comment Excerpt Number: 27

Comment: Revise §98.33(a)(3)(iii) Equation C-5 and §98.253(b)(1)(ii)(B) Equation Y-2 to revise the term “MVC” to be consistent with changes proposed in other parts of the rule. Additionally, revise the reporting requirements at §98.36(e)(2)(iv)(B).

Response: Please see the response to comment EPA-HQ-OAR-2008-0508-2402.1, excerpt 2, in Section 3 of this document, for the response to this comment.

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2008-0508-2383.1

Comment Excerpt Number: 33

Comment: The amended Subpart Y provided an alternative Molar Volume Correction (MVC) term of 836.6 scf/kg-mole at 60 F and 14.7 psia. API supports this revision and requests that this alternative MVC be provided in all subparts that address gaseous streams.

Response: Please see the response to comment EPA-HQ-OAR-2008-0508-2402.1, excerpt 2, in Section 3 of this document, for the response to this comment.

Commenter Name: Craig Holt Segall

Commenter Affiliation: Sierra Club Environmental Law Program et. al

Document Control Number: EPA-HQ-OAR-2008-0508-2398.1

Comment Excerpt Number: 17

Comment: One of the goals of the GHG reporting rule is to enable regulators to compare emission sources and efficiently reduce GHG emissions. EPA’s proposal to allow refineries to report CO₂ emissions from refinery fuel gas combustion at smaller process heaters using Tier 1 and Tier 2 methodologies will undermine this goal. The proposal will allow refiners to estimate CO₂ emissions from process heaters that 1) have capacities less than 30 mmBtu/hr or average annual flow rates less than 345 scfm and 2) no flow meter installed based on sporadic sampling of higher heating value (HHV) or fixed assumptions and company records about fuel consumption. 75 FR 48772. Tier 3 requires refineries to report emissions by measuring flow rates and carbon content. 40 C.F.R. § 98.33(a)(3).

The Tier 1 and 2 methodologies are inaccurate because they do not account for the variable carbon content of refinery fuel gas. The Tier 1 assumes a constant HHV value as a proxy for carbon content. *Id.* at § 98.33(a)(1). This will result in inaccurate reporting because HHV significantly fluctuates in refinery fuel gas. While Tier 2 requires refiners to report emissions based on periodic HHV measurements this is not sufficient. 40 C.F.R. § 98.33(a)(2). HHV measures hydrogen content as well as carbon content. Petroleum Refining Support Document at 20. Hydrogen in refinery fuel gas does not contribute to CO₂ emissions. *Id.* at 20. Therefore, either of these methodologies will result in inaccurate CO₂ emissions reporting.

EPA's justification for this change is that it will ease the burden on smaller refiners and that these refiners only account for 2% of the national refining capacity. 75 FR 48772. Implied in this statement is that these emissions are too small to worry about. While it logically follows that the process heater in question produces a small percentage of refinery emissions, it is not apparent that these emissions are negligible from a national inventory standpoint. Leaving the quantity of emissions aside, EPA's justification misses the point. The goal of collecting this data is to compare emission rates between refineries. Because most of these smaller process heaters are at smaller refineries, it will be difficult to compare GHG emission rates of small refineries against large refineries. It will also be difficult to compare CO₂ emission rates of small process heaters against large process heaters. Without the ability to make these comparisons, EPA won't be able to make educated decisions regarding the most efficient targets for reducing GHGs. Therefore, EPA must insist that refineries use Tier 3 methodologies on all process heaters. If EPA does conclude that Tier 3 methodologies are not warranted for these smaller process heaters, EPA should at least require Tier 2 methodologies.

Response: We agree that one of the goals of the GHG reporting rule is to enable regulators to compare emission sources and develop effective climate policies; however, we disagree that the limited flexibility provided in the proposed amendments for small process heaters or small fuel gas lines that are not equipped with flow meters will undermine this goal. First, some small process heaters will continue to use Tier 3 because they have a flow meter either at the process heater or at an upstream common pipe, as indicated by other comments received requesting a broader exclusion for these small process heaters. Thus, we will be collecting some data by which to more accurately characterize smaller process heaters.

Second, we proposed to provide additional flexibility in calculating emissions for certain small process heaters or fuel gas lines because, based on the Agency's experience with the fuel gas standards in 40 CFR part 60 subpart J, we did not expect that there would be a significant number of fuel gas lines that were not part of a centralized fuel gas system monitor. We estimated the cost of installing fuel flow meters only on larger, common pipe configurations. For the small number of large (centralized) fuel gas lines, we determined that the Tier 3 monitoring requirements were appropriate and justified. However, when we consider the cost associated with imposing Tier 3 requirements on small process individual process heaters or fuel gas lines (e.g., those that are not part of a centralized fuel gas system), we arrive at a different conclusion. We estimate the cost of installing fuel gas flow meters on individual small fuel gas lines would exceed \$0.50 per ton of CO₂ reported, which we determined to be unacceptable. (As shown in Table 5-2 of the Regulatory Impact Analysis for the Mandatory Reporting of Greenhouse Gases Final Rule (GHG Reporting) Final Report (EPA-HQ-OAR-2008-0508)

September 2009, the cost/ton of CO₂ emissions reported is significantly lower across all of the subparts in the rule.)Therefore, we provided this limited flexibility for small process heaters or fuel gas lines that do not have a flow meter installed in the line or in an upstream common pipe. While we estimated the potential impact of this flexibility by considering the emissions produced by all process heaters with a capacity of less than 30 MMBtu/hr, we note that this is the maximum potential impact and that a large number of these small process heaters will not qualify for the limited flexibility.

Third, it is likely that some facilities will elect to use Tier 2 for high hydrogen- or nitrogen-containing process gas streams that are not well characterized by the Tier 1 default Btu content for fuel gas. While we consider the Tier 1 default Btu content for fuel gas in Table C-1 to be representative of the primary sources of fuel gas within the refinery, the Tier 1 defaults will typically overstate the emissions from these high hydrogen- or nitrogen-containing process gas streams. Consequently, some facilities may elect to use Tier 2 rather than overstate these emissions. However, we decided not to require Tier 2 for these sources because both Tier 1 and Tier 2 are expected to have significant uncertainties. Given the high uncertainties of both Tier 1 and Tier 2, we conclude that there is little benefit for requiring Tier 2 over Tier 1 in this situation because the higher uncertainty of either method is acceptable based on the very small percentage of combustion emissions represented by the small process heaters or fuel gas lines that do not have flow meters installed.

In summary, we are finalizing the amendments to allow certain small process heaters and fuel gas lines to use Tier 1 or Tier 2, in lieu of Tier 3, monitoring requirements as proposed. When flow meters are installed on small process heaters or fuel gas lines (or an upstream common pipe), the Tier 3 methodology must be followed. When flow meters are not installed, Tier 3 becomes too costly when considering the relatively small quantity of CO₂ emissions. Therefore, when flow meters are not installed on small process heaters or fuel gas lines, either Tier 1 or Tier 2 may be used.

Monitoring and QA/QC Requirements

Commenter Name: Michael Hannan

Commenter Affiliation: Williams Olefins LLC

Document Control Number: EPA-HQ-OAR-2008-0508-2357.1

Comment Excerpt Number: 48

Please see the summary and response to comment EPA-HQ-OAR-2008-0508-2357.1, excerpt 47, in Section 9 of this document, for the summary and response to parallel comments made on the monitoring and QA/QC requirements in subparts X and Y.

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2008-0508-2383.1

Comment Excerpt Number: 14

Comment: The October 2009 final rule required exhaust gas flow meters used to comply with the §98.253(c)(2)(ii) for catalytic cracking units to be installed, operated, calibrated and maintained according to the Refinery MACT [Petroleum Refinery NESHAP] requirements in §63.1572(c). EPA proposes to revise §98.254(f) to also require exhaust gas flow meters used to comply with the §98.253(j) requirements for process vents not covered in §98.253(a) through (i) to be installed, operated, calibrated and maintained according the Refinery MACT requirements in §63.1572(c).

The Refinery MACT requirements in §63.1572(c) contain provisions that are more stringent than the monitoring and QA/QC requirements throughout the GHGRP. For example, §63.1572(c) requires each monitoring system to have valid hourly average data from at least 75% of the hours during which the process operated and to complete a minimum of one cycle of operation for each successive 15-minute period with a minimum of four successive cycles of operation to have a valid hour of data (or at least two if a calibration check is performed during that hour or if the continuous parameter monitoring system is out-of-control). Since the flow monitoring requirements for Refinery MACT in §63.1572(c) were established to demonstrate compliance with emission limits, they should not be used as a template for requirements of flow metering for GHG reporting. Hence, the process vent exhaust flow meter requirements should be consistent with the requirements for other gas flow meters throughout the GHGRP such as flare and sour gas flow meters.

API requests that EPA not revise §98.254(f) but instead revise §98.254(c) for flare and sour gas flow meters to also include flow meters used to comply with §98.253(j) [process vents not covered in §98.253(a) through (i)].

Response: Please see Section II.N of the preamble to the final rule amendments for the response to this comment.

Commenter Name: Craig Holt Segall

Commenter Affiliation: Sierra Club Environmental Law Program et. al

Document Control Number: EPA-HQ-OAR-2008-0508-2398.1

Comment Excerpt Number: 18

Comment: EPA is proposing to allow refineries to use any chromatographic analysis to determine flare gas composition and HHV provided the gas chromatograph is operated according to the manufacturer's specifications. 75 FR 48774. EPA has already provided five different methods to measure flare gas composition and another five methods to measure flare gas higher heating value. 40 C.F.R. § 98.254(d)-(e). Different methods for chromatographic analysis may provide emission measurements that are not comparable. Because this exception potentially allows as many methods as there are manufacturers, it will make comparative analysis that much more difficult. As a result, EPA and the public will be in the dark about comparative emission rates between different refineries. We urge EPA to abandon this exception.

Response: We added the flexibility in the proposed amendments to use other gas chromatographic methods to acknowledge the fact that there may be other appropriate methods that reporters could use in addition to those we included in the October 30, 2009, final rule. However, we disagree with the assertion that the flexibility provided in the proposed amendments would lead to incomparable results. The mere fact that different methods may be used to analyze data does not per se mean the resulting data cannot be compared. These different gas chromatography methods should yield comparable results provided the appropriate calibrations and quality assurance checks are conducted. Gas chromatography methods other than those we specifically identified can provide accurate compositional analyses provided the appropriate calibrations and quality assurance checks are conducted. Therefore, when another gas chromatography method is used, the proposed amendments requires the chromatograph be operated, maintained and calibrated according to the manufacturer's instructions and that the methods be documented in the facility's Monitoring Plan. By including these additional requirements on these "other" chromatography methods, the data received should be comparable to data generated by the other methods specifically listed in the rule. Other than conclusory allegations to the contrary, the commenter does not provide any support for its objection. Consequently, we are finalizing this amendment as proposed.

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2008-0508-2383.1

Comment Excerpt Number: 36

Comment: API supports the revision of §98.254(c) – Deleted list of list of procedures for flare and sour gas meters.

Response: EPA thanks the commenter for the input. We have finalized the amendments as proposed.

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2008-0508-2383.1

Comment Excerpt Number: 37

Comment: API supports the revision of §98.254(d) – Allows the use of gas chromatograph analyses to determine the gas composition and molecular weight.

Response: EPA thanks the commenter for the input. We have finalized the amendments as proposed.

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)
Document Control Number: EPA-HQ-OAR-2008-0508-2383.1
Comment Excerpt Number: 38

Comment: API supports the revision of §98.254(e) – Allows the use of gas chromatograph analyses to determine the flare gas HHV.

Response: EPA thanks the commenter for the input. We have finalized the amendments as proposed.

Other Subpart Y Comments

Commenter Name: Michael Hannan
Commenter Affiliation: Williams Olefins LLC
Document Control Number: EPA-HQ-OAR-2008-0508-2357.1

Comment: The commenter noted that the proposed amendments to 40 CFR 98.7 would add a new paragraph 98.7(e)(43) to incorporate by reference ASTM D2503-92 (Reapproved 2007) Standard Test Method for Relative Molecular Mass (Molecular Weight) of Hydrocarbons by Thermoelectric Measurement of Vapor Pressure, for §98.254(d) of Subpart Y. The commenter noted that this method is already listed in 40 CFR 98.7(e)(15); therefore, this paragraph only needs to be amended to add §98.254(d), and a new paragraph does not need to be added to §98.7(e).

Response: The commenter is correct. Addition of ASTM D2503-92 should be done by amending §98.7(e)(15).

Commenter Name: Jamie Mann
Commenter Affiliation: Suncor Energy USA, Inc.
Document Control Number: EPA-HQ-OAR-2008-0508-2389.1
Comment Excerpt Number: 4

Comment: EPA states that this proposed rule does not contain a Federal mandate that may result in expenditures of \$100 million or more for State, local, and tribal governments, in the aggregate, or the private sector in anyone year. EPA has estimated that, overall, the proposed revisions do not significantly change the overall costs of compliance with Part 98. The proposed amendments include providing additional flexibility for reporters, clarifying existing reporting requirements, and requiring reporting of information already required to be collected under Part 98.

EPA estimates that the cost for all reporters in reviewing the proposed rule and determining if, and if so how, it applies to their facility, is approximately \$2.5 million in the first year. Considering the additional flexibilities proposed, in sum, EPA has estimated that the proposed rule, if finalized, would reduce the burden to reporters as compared to the 2009 final rule. Thus,

this rule is not subject to the requirements of sections 202 or 205 of Unfunded Mandates Reform Act (UMRA). For more information on the cost analysis, please refer to the memorandum titled "Mandatory Greenhouse Gas Reporting: Changes in National Cost Estimates Associated with the Proposed Notice of Revisions" found in the docket at (EPA-HQ-OAR-2008-0508).

Suncor Energy U.S.A., Inc. (Suncor) believes that the revised cost analysis does not appear to accurately represent the costs to either install multi-variable transmitters on flow meters to measure temperature, pressure and flow at the same location for every flow meter or the costs associated with developing the documentation to demonstrate that the use of common temperatures and pressures satisfies the rule (i.e., the ability to compensate for all ambient conditions on a daily basis for every flow meter).

Suncor has reviewed the memorandum titled "Mandatory Greenhouse Gas Reporting: Changes in National Cost Estimates Associated with the Proposed Notice of Revisions" for the October 30, 2009 rule, in which EPA indicated that cost impacts to a single petroleum refinery was as follows [Note: Preamble of the MRR, Page 56363, Table VII "Estimated Covered Entities, Emissions, Costs by Subpart (2006\$)"]:

- (1) \$10,666/yr (5 yr annualized cost \$1.6 M /150 refineries)
- (2) \$40,667 year 1 costs (\$6.1 M /150 refineries)

Recent data presented in a white paper [Note: "A Survey of Refinery MRR GHG Emission Inventory Efforts," Matthew Harrison, URS Corporation] at the National Petrochemical and Refiners Association (NPRA) Conference indicates that the average cost of implementing the GHG Mandatory Reporting Rule, actually is much higher than was projected by EPA. According to the author of the abovementioned white paper "the survey clearly shows that actual incurred costs have far exceeded EPA's OMB approved estimates by almost an order of magnitude for year 1 (a factor of 8.8 higher) ... Capital costs are clearly higher than EPA projected. Even without the capital costs, each refinery was spending almost \$112,000 in internal and external costs for MRR compliance to date."

Given this background, coupled with site-specific cost projections, Suncor requests that EPA reevaluate the assumptions contained in its cost analysis. Suncor also requests that EPA reconsider whether the total costs to the private sector to implement the proposed updates to the rule is greater than the \$100 million threshold under the Unfunded Mandates Reform Act.

Response: We maintain that the costs of the proposed amendments are far less than \$100-million in any one year. Please note that the costs are specific to the proposed amendments and not to the aggregate cost of the Oct. 30, 2009, final mandatory reporting rule. We agree that the final rule posed costs exceeding \$100-million in any one year and we already have complied with the requirements of the Unfunded Mandates Reform Act in the promulgation of that final rule.

However, the amendments we proposed do not increase burden on the regulated community. On the contrary, we believe that the amendments reduce the burden of the final rule and, therefore, we only estimated the incremental costs of the amendments as those associated with reading and understanding the amendments. The commenter's particular concern is that the cost analysis (for

the proposed amendments) does not appear to accurately represent the costs to either install multi-variable transmitters on flow meters to measure temperature, pressure and flow at the same location for every flow meter or the costs associated with developing the documentation to demonstrate that the use of common temperatures and pressures satisfies the rule (i.e., the ability to compensate for all ambient conditions on a daily basis for every flow meter).

First, we note that we interpreted the final rule to require measurement of temperature and pressure at the same location as the flow meter (when needed to correct flow to standard conditions). Second, we relaxed the flow monitoring requirements to allow use of temperature and pressure monitors at locations other than the flow meter. We did not need to estimate costs associated with developing the documentation to demonstrate that the use of common temperatures and pressures satisfies the rule (i.e., the ability to compensate for all ambient conditions on a daily basis for every flow meter) because the reporter could always elect to install and use temperature and pressure monitors at the flow monitor as required in (and included in the costs of) the final rule. That is, we assume that reporters will elect to use remote temperature and pressure monitors only when they result in a cost savings compared to installing the temperature and pressure monitors at the flow meter. As such, we consider that the amendment specifically cited by the commenter is an example of an amendment that actually reduces the burden of the final rule.

The commenter cited our previous cost estimates, suggesting that the previous cost estimates were understated. First, this argument is not really relevant with respect to whether or not the proposed updates to the rule cause an increase in the costs (relative to the final rule) greater than the \$100 million threshold under the Unfunded Mandates Reform Act. To the extent the commenter is challenging the costs from the original 2009 final rule, that comment is outside the scope of this rulemaking. Second, actual costs incurred by certain reporters can be significantly higher than our estimates without our estimates being understated. The costs we develop are based on the costs needed to minimally comply with the rule and are averaged over all refineries. Some refineries in our analysis had projected costs much higher than the average compliance costs. Furthermore, reporters are free to elect other, higher cost monitoring alternatives than those minimally required. For example, to comply with the Tier 3 monitoring requirements for fuel gas, the reporter may elect to install a continuous on-line gas chromatograph (GC) rather than to take the required weekly grab samples. The costs associated with on-line GC will be greater than those for weekly sampling, but the continuous monitor may also provide for safer operation and improved process control, so the reporter *elects* to spend more than the rule would *require* for this reporting element. As another example, some reporters may elect to monitor at individual combustion sources rather than at a common pipe because monitoring at the individual unit also supplies the reporter with additional information with which to evaluate the performance and efficiency of that specific unit. Additionally, while the rule requires reporting at the facility level, some corporations may impose additional levels of review, recordkeeping, reporting, and even monitoring requirements as part of corporate oversight. Our cost estimates do not include costs associated with these additional layers of management or optional information. Thus, when facilities report actual costs incurred with complying with a rule, they generally include the total costs incurred, including additional costs associated with facility or corporate preference rather than those strictly mandated by the rule. As a result, these facility-

reported costs can exceed the costs estimated by EPA without indicating that EPA's mandated costs estimate is inaccurate.

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2008-0508-2383.1

Comment Excerpt Number: 18

Comment: API supports retaining the previously promulgated equations in 40 CFR 98.253 and the flexibility to use either of the methods presented. If EPA were to replace the original equations with those proposed as part of this amendment, refineries would have to modify their data management systems which, this late in the reporting year, will impact the ability to meet the March 31 reporting deadline.

Response: We agree and are finalizing the amendments as proposed to provide the new equations as alternatives to the existing equations.

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2008-0508-2383.1

Comment Excerpt Number: 42

Comment: One of the methodologies provided in §98.253(l) for calculating emissions from equipment leaks is to use Equation Y-21 and enter into it the number of specified process units (catalytic cracking units, coking units, hydrocracking units, distillation columns, etc). For distillation columns, it is not clear if columns associated with the other process units listed are to be counted separately; namely did EPA intend to include distillation units among the rest of the units, or did it actually mean distillation columns? For example, if a refinery has one catalytic cracking unit and the catalytic cracking unit includes a depropanizer column, is the column considered part of the catalytic cracking unit so N_{PU1} in the equation equals 1, or is the column considered a separate process unit so N_{PU1} in the equation equals 2? EPA should clarify the default method to state that it applies to distillation units and not to individual distillation columns that might be part of other units.

Response: EPA thanks the commenter for the input. No rule change has been made as a result of this comment. The changes to Part 98 suggested by the commenter are outside the scope of the specific amendments proposed for public comment in the Federal Register notice of August 11, 2010. We will be providing guidance on Part 98 to address the commenter's concerns.

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2008-0508-2383.1

Comment Excerpt Number: 43

Comment: In section §98.253(k) Equation Y-20 provides a calculation method for uncontrolled blowdown systems. The equation applies a default emission factor to the total volume of crude oil and intermediate products that enters the refinery for processing. Neither the rule nor the Petroleum Refining TSD provides any reference or origin for the default CH₄ emission factor of 137,000 scf CH₄/MMbbl that is provided with the equation.

EPA uses this same factor in the national inventory (Table A-124 in the 2006 inventory) and the source cited in EPA's inventory is a 1999 report "CH₄ Emissions for the U.S. Petroleum Industry". The 1999 report was an attempt to mimic the 1996 GRI/EPA study, but for the petroleum side, and without any new measurements (i.e., relying only on published information).

The 1999 EPA report bases the CH₄ factors for uncontrolled refinery blowdown systems on a 1977 report "Revision of Emission Factors for Petroleum Refining" (EPA-450/3-77/030). The 1977 report aimed to update VOC emissions factors and provided a factor in terms of hydrocarbon emissions from refinery blowdown activities. For the 1999 EPA report, the authors assumed 1% CH₄ content and converted the VOC based factor to a CH₄ basis.

The 1977 VOC factor and its 1999 update to CH₄ clearly do not represent current industry practices as far as refinery blowdown systems, since many rules have been put in place since then to control VOC emissions from refineries (for example, refinery MACT rules).

Also the factors cited were developed for "top down" assessment of CH₄ emissions from the refining sector and are not applicable for use in the context of facility reporting where EPA's emphasis is on acquiring quality data that is based on current operational practices.

API is requesting EPA to clarify what sources EPA view as being included in this category of uncontrolled refinery blowdown systems, since refinery industry vents are so heavily controlled already. API recommended revising or discarding Equation Y-20 and the requirement to report emissions from refinery blowdown systems since they are insignificant, or at most a very small percentage of GHG emissions in refineries.

Response: The term "blowdown" is defined in §98.6. The distinction of controlled and uncontrolled blowdown system is provided in §98.253(j). Thus, an "uncontrolled blowdown system" refers to the system used to manage gases and/or liquids that are generated due to emptying or depressuring a vessel (which typically includes knock-out pot for collecting and recovering entrained liquids) that subsequently discharges any uncondensed gas streams directly to the atmosphere.

We do anticipate that most blowdown systems will be controlled and that some refineries may not have any uncontrolled blowdown systems.

We acknowledge that there are limited data available for estimating the emissions from these "atmospheric vents" from blowdown systems, which highlights the need for obtaining better data and to require reporting of these emissions. We also note that the method for process vents (Equation Y-19) can be used for these blowdown vents. We are hopeful that better data for uncontrolled blowdown systems may be collected due to facilities utilizing this option.

11. SUBPART AA - PULP AND PAPER MANUFACTURING

No public comments were received on the proposed amendments to Subpart AA.

12. SUBPART NN - SUPPLIERS OF NATURAL GAS AND NATURAL GAS LIQUIDS

EPA proposed amendments to the applicability criteria for this source category that are found in 40 CFR part 98, subpart A, at §98.2(a)(4)(iii)(B). These comments and EPA's responses are found in Section 1 of this document.

13. SUBPART OO - SUPPLIERS OF INDUSTRIAL GREENHOUSE GASES

Monitoring and QA/QC Requirements

Commenter Name: Joel R. Hall

Commenter Affiliation: Mexichem Fluor Inc.

Document Control Number: EPA-HQ-OAR-2008-0508-2365

Comment Excerpt Number: 10 and 11

Comment: Mexichem requests that the EPA not mandate measurement of the concentration of all fluorinated GHGs coming out of the production process if the mass coming out of the process includes only one fluorinated GHG product and low concentration constituents, or allow the use of alternative methods for the determination of the concentration of fluorinated GHGs coming out of the process.

The mass of fluorinated GHGs coming out of Mexichem's production process consists of only HFC-134a and impurities that meet the definition of "low concentration constituents" (<0.1% by mass). Therefore, under the proposed rule [amendments] the mass of all material coming out of the process would be considered HFC-134a. The proposed rule does not require that the concentration(s) of low concentration constituents be measured, but also does not exclude the measurement of the concentration of one fluorinated GHG present in concentrations above the low concentration constituent threshold (0.1% by mass). Mexichem Fluor requests that the final

rule exclude the measurement of fluorinated GHGs coming out of the process when the mass includes only one fluorinated GHG present above the low concentration constituent threshold.

Mexichem currently, and for the history of the site, has determined the purity of its product by using AHRI 700C-2008: Appendix C to AHRI Standard 700 - Analytical Procedures for AHRI Standard 700-06 (Determination of Purity of New and Reclaimed R-22, R-32, R-113, R-134a, R-141b, R-142b, and R-245fa by Capillary Column Gas Chromatography). This method is applicable to the determination of impurities typically present in the commercially manufactured and reclaimed refrigerants referenced above. The concentration of product is determined by subtracting the concentrations of the impurities. This method is used on each batch tank of product manufactured at the site. Mexichem would need to invest capital in order to utilize the methods referenced in the proposed rule and the additional quality control criteria of those methods would result in additional and unnecessary burden. As the method currently used by Mexichem is an industry standard, Mexichem requests that alternative methods, such as industry standards, be allowed in the final rule.

Response: We are finalizing the proposed requirement at §98.414(n) to measure the concentrations of all the fluorinated GHGs, other than low-concentration constituents, in the product. While the rule excludes low-concentration constituents from the requirement to measure and report the concentrations of the fluorinated GHGs coming out of the process, this is in recognition of the impracticality of measuring low concentrations of fluorinated GHGs. The exclusion is not intended to exempt product streams from concentration measurements because facilities believe that these streams contain only the primary constituent (e.g., HFC-134a in the commenter's example) and low-concentration constituents. The reason the measurement is required is either to verify that the concentrations of the other fluorinated GHGs are in fact low enough to qualify them as low-concentration constituents (i.e., below 0.1 percent), or to identify and quantify concentrations of fluorinated GHGs that are not low-concentration constituents.

Also as proposed, we are providing flexibility to facilities to use "other analytical methods validated using EPA Method 301 or some other scientifically sound validation protocol." As a widely-used industry method, the method cited by the commenter has probably been validated with the analytes of interest at the concentrations of interest using a scientifically sound validation protocol. However, if the facility could not confirm and document this, the facility could validate the method itself using EPA Method 301 or another scientifically sound validation protocol, or the facility could document that the method is essentially identical to one of the methods listed at §98.414(n).

Commenter Name: Helen D. Silver

Commenter Affiliation: Clean Air Task Force et. al

Document Control Number: EPA-HQ-OAR-2008-0508-2403.2

Comment Excerpt Number: 9

Commenter Name: Craig Holt Segall

Commenter Affiliation: Sierra Club Environmental Law Program et. al

Document Control Number: EPA-HQ-OAR-2008-0508-2398.3

Comment Excerpt Number: 9

These two commenters submitted identical comments on this subject.

Comment: American industry produces hundreds of thousands of tons of fluorinated gases, including HFCs, PFC, SF₆, NF₃, HFEs, CFCs, and HCFCs annually – on the order of 440,000 tons a year, according to EPA. [Footnote: See EPA, Technical Support Document (Updated) for Emissions from Production of Fluorinated Gases (Mar. 22, 2010) (Fluorinated Gas TSD”) at 4.] Given the persistence of such gases in the atmosphere and their high global warming potential (“GWP”), these gases, if emitted, would translate into hundreds of millions of tons of CO₂ [equivalents]. Data on the supply of these gases are therefore critical, and we are concerned that some of EPA’s proposed revisions pursuant to its settlement agreement with the American Chemistry Council sacrifice data accuracy for this important sector.

Based on its settlement agreement, EPA proposes to exclude from monitoring, reporting, and recordkeeping requirements fluorinated GHGs that occur as low-concentration constituents of fluorinated GHG products. For fluorinated GHG production and export, EPA proposes to define a low-concentration constituent as a constituent that occurs in the product in concentrations below 0.1 percent by mass. For fluorinated GHG import, EPA proposes to define low-concentration constituents as those that occur in concentrations below 0.5 percent by mass. Given the high GWP of these gases, however, even relatively small masses of these gases could have significant global warming impacts. In its 4th Assessment Report, IPCC recognized that these gases “have extremely long atmospheric lifetimes (thousands of years) and GWP values (thousands of times those of CO₂) resulting in virtually irreversible atmospheric impacts.”

Given EPA’s emphasis on CO₂e measurements, we are concerned that EPA’s reliance on a mass-based de minimis exclusion here improperly exempts a significant amount of emissions from reporting. We ask the Agency to provide additional information on the GWPs of these low-concentration constituents and the emissions affected by this proposed change. If significant emissions are lost from the rule as a result, EPA should not make the change.

We are likewise concerned with the Agency’s proposal to exclude fluorinated GHGs that are emitted or destroyed before the fluorinated product is packaged for sale. Emissions from the fluorinated GHG production process are significant, accounting for roughly 10.6 mmtCO₂e annually. EPA accounts for many of these emissions under Subpart L, fluorinated GHG production, and EPA notes that these intermediate emissions might more properly fall under this subpart because they are not placed into the stream of commerce. Regardless of subpart under which facilities are required to report these emissions, we encourage the Agency to ensure that these intermediate emissions are fully captured under the reporting rule and ask that it document the magnitude of these emissions, the identities and GWPs of compounds in this group, and the emissions affected by the proposed change. Again, if significant emissions are lost from the rule as a result, EPA should not make the change.

Response: Please see Section II.Q of the preamble to the final rule amendments for the response to this comment.

Definitions

Commenter Name: Joel R. Hall

Commenter Affiliation: Mexichem Fluor Inc.

Document Control Number: EPA-HQ-OAR-2008-0508-2365

Comment Excerpt Number: 8

Comment: It is not clear whether an intermediate that is created and transformed in a single process with no storage of the intermediate is required to be reported under 40 CFR 98.416(a)(2). Mexichem believes that intermediates that meet this definition are not to be reported under §98.416(a)(2) because the proposed definition for the source category specifically excludes the “creation of fluorinated GHGs that are released or destroyed at the production facility before the production measurement at §98.414(a).” Mexichem requests that the EPA clarify in the final rule that §98.416(a)(2) only applies to isolated intermediates.

Response: Under subpart OO, we are not requiring reporting of either the production or the transformation of intermediates that are created and transformed in a single process with no storage of the intermediate. The definition of “produce a fluorinated GHG” states: “Producing a fluorinated GHG does not include . . . the creation of intermediates that are created and destroyed in a single process with no storage of the intermediates.” We excluded such intermediates from the definition of “produce a fluorinated GHG” because it would be impracticable to measure and report their production. It would be similarly impracticable to measure and report their transformation. In addition, monitoring and reporting the transformation of fluorinated GHGs that were never counted as produced would not enhance our understanding of the fluorinated GHG supply; instead, it could lead to an underestimate of that supply

Other Subpart OO Comments

Commenter Name: Rich Raiders

Commenter Affiliation: Arkema Inc.

Document Control Number: EPA-HQ-OAR-2008-0508-2371.1

Comment Excerpt Number: 2

Comment: The Subpart OO applicability provisions clearly delineate how fluorochemical manufacturers identify and report fluorinated greenhouse gases (“GHG”) that have entered or exited commerce.

Response: EPA thanks the commenter for the input.

Commenter Name: Joel R. Hall

Commenter Affiliation: Mexichem Fluor Inc.

Document Control Number: EPA-HQ-OAR-2008-0508-2365

Comment Excerpt Number: 7

Comment: Mexichem generally supports the proposed changes to Subpart OO. We believe these proposed changes provide clarity and will ensure consistency in reporting under this subpart.

Response: EPA thanks the commenter for the input.

Commenter Name: Lorraine Krupa Gershman

Commenter Affiliation: American Chemistry Council

Document Control Number: EPA-HQ-OAR-2008-0508-2368.1

Comment Excerpt Number: 9

Comment: ACC supports all of EPA's proposed changes to subpart OO. If finalized as proposed, these changes will address the more serious issues identified by producers of fluorinated GHGs with the original subpart OO language.

Response: EPA thanks the commenter for the input.

Commenter Name: Joel R. Hall

Commenter Affiliation: Mexichem Fluor Inc.

Document Control Number: EPA-HQ-OAR-2008-0508-2365

Comment Excerpt Number: 9

Comment: The data required under 40 CFR 98.416(a)(8) and (9) are not relevant to Subpart OO and should not be reported there under. 40 CFR 98.416(8) and (9) require the reporting of total mass in metric tons of each reactant fed into the F-GHG or nitrous oxide production process, by process and total mass in metric tons of the reactants, by-products, and other wastes permanently removed from the F-GHG or nitrous oxide production process, by process. The EPA has made it clear that they are proposing to modify Subpart OO to "explicitly exclude the "creation of fluorinated GHGs that are released or destroyed at the production facility before the production measurement at § 98.414(a)."

The data required under §98.416(a)(8) and (9) are relevant to the creation of fluorinated GHGs before the production measurement at §98.414(a) and therefore should not be reported under Subpart OO. Mexichem requests that these reporting requirements be removed from the final rule.

Response: No rule change has been made as a result of this comment. The changes to Part 98 suggested by the commenter are outside the scope of the specific amendments proposed for public comment in the Federal Register notice of August 11, 2010. However, for a discussion of the rationale behind the reporting requirements at 40 CFR 98.416(a)(8) and (9), please see the response to comments document for subpart OO for the October 30, 2009 final Mandatory Reporting Rule, (Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart OO—Suppliers of Industrial Greenhouse Gases), comment number EPA-HQ-OAR-2008-0508-0408.1, excerpt 24.

14. SUBPART PP - SUPPLIERS OF CARBON DIOXIDE

Calculating CO₂ Supply

Commenter Name: Tom Siegrist

Commenter Affiliation: Koch Nitrogen Company LLC (KNC)

Document Control Number: EPA-HQ-OAR-2008-0508-2364.1

Comment Excerpt Number: 3

Comment: EPA’s proposal to allow suppliers that supply CO₂ in containers to calculate the annual mass of CO₂ supplied in containers by using weigh bills, scales, load cells, or loaded container volume readings, as an alternative to flow meters, reduces the reporting burden while maximizing reporting flexibility. (75 FR 48779)

EPA concluded that measurements made using weigh bills, scales, load cells, or loaded container volume readings would meet the level of data quality and accuracy needed by EPA (75 FR 48779). This proposed approach would also accurately reflect the quantity of CO₂ actually sent off-site for commercial use, while providing reporters with flexibility as to their point of measurement for compliance purposes. Koch Nitrogen Company, LLC (KNC) supports EPA’s proposal to accept alternative points and methods of measurement.

Response: EPA thanks the commenter for the input. We have finalized the amendments as proposed.

Equation PP-1

Commenter Name: Rich Raiders

Commenter Affiliation: Arkema Inc.

Document Control Number: EPA-HQ-OAR-2008-0508-2371.1

Comment Excerpt Number: 7

Comment: Proposed §98.423(b) allows CO₂ reporters supplying product in “containers” to utilize calibrated weigh scales to determine the mass of CO₂ supplied into the market. Please clarify that “containers” may include, in addition to common packaging cylinders, tank trailers. One Arkema facility ships CO₂ in tank trailers by truck, and could readily utilize the proposed container reporting system as a primary or alternate supply reporting system.

Response: EPA is clarifying here that containers include tank trailers.

Equation PP-2

Commenter Name: Tom Siegrist

Commenter Affiliation: Koch Nitrogen Company LLC (KNC)

Document Control Number: EPA-HQ-OAR-2008-0508-2364.1

Comment Excerpt Number: 4

Comment: EPA’s proposal to remove the requirement that CO₂ measurement be made prior to subsequent purification, processing, or compression correctly reflects the real-world situation where such a location would not accurately reflect the quantity of CO₂ actually available for off-site commercial use (75 FR 48779).

The current regulatory language could be interpreted to require that facilities measure CO₂ flow prior to purification, processing, or compression, even if a portion of that flow is diverted for on-site use downstream of purification, processing, or compression. Measurement at the currently required point in the process would over-estimate the amount of CO₂ available for off-site commercial use. EPA’s proposal would eliminate this problem. Whereas EPA has concluded that measurements made after purification, processing, or compression would meet the level of data quality and accuracy needed for this subpart (75 FR 48779), Koch Nitrogen Company, LLC (KNC) supports the proposed removal of language requiring upstream measurement.

Response: EPA thanks the commenter for the input. The final rule removes the requirement that CO₂ measurement be made prior to subsequent purification, processing, or compression.

Commenter Name: Tom Siegrist

Commenter Affiliation: Koch Nitrogen Company LLC (KNC)

Document Control Number: EPA-HQ-OAR-2008-0508-2364.1

Comment Excerpt Number: 5

Comment: EPA’s proposal to require that the CO₂ flow meter be located after the point of segregation for on-site use would unfairly penalize those facilities that have installed a flow meter according to the current regulatory requirements, and EPA should provide other options for compliance. (75 FR 48780)

The current regulatory language required CO₂ suppliers to have meters installed and calibrated before April 1, 2010. Facilities that installed a CO₂ meter in compliance with the applicable regulatory language – at a location prior to purification, processing, or compression – should not now be required to install a meter after the point of segregation for on-site CO₂ use where they have other means to generate the data needed by EPA. Rather, facilities that installed a meter ahead of purification, processing, and compression and also ahead of segregation for on-site use should have the option to include an appropriately calibrated meter on the on-site diversion flow in their GHG reporting program. KNC notes that it has been utilizing the two-meter approach at one of its facilities since March 31, 2010. The calculated difference between the two meter readings would provide an accurate estimate of the quantity of CO₂ available for off-site commercial use. Koch Nitrogen Company, LLC (KNC) believes that either this two-meter option or the option of using a single meter located after purification, processing, compression and downstream of any diversion for on-site use should be equally acceptable under the rule.

Response: Please see Section II.R of the preamble for the final rule amendments for the response to this comment.

Commenter Name: Rich Raiders
Commenter Affiliation: Arkema Inc.
Document Control Number: EPA-HQ-OAR-2008-0508-2371.1
Comment Excerpt Number: 8

Comment: In several other Part 98 subparts, EPA recognizes calibrated truck scales as appropriate supply measurement determination techniques. EPA should also make a conforming edit to proposed §98.424(a)(1)(i) and (a)(1)(iii) to incorporate weigh scale monitored shipping of CO₂ product.

Response: Today's final action provides the flexibility the commenter requested regarding calibrated truck scales. 40 CFR Part 98.424(a)(2) contains QA/QC requirements for weigh scales and was added in the proposal to apply to reporters following the procedures for containers in 40 CFR Part 98.423(b). Therefore, 40 CFR Part 98.424(a)(1)(i) and (iii) are not relevant to reporters using truck scales to determine the quantity of CO₂ supplied. The proposed organization has been retained in the final rule amendments, and no revision was made as a result of this comment.

Commenter Name: Karin Ritter
Commenter Affiliation: American Petroleum Institute (API)
Document Control Number: EPA-HQ-OAR-2008-0508-2383.1
Comment Excerpt Number: 40

Comment: Third Party Quantity Measurements in Subparts MM, NN and PP
EPA's MRR Subpart MM requires information to assure EPA that these measurements are being made accurately. This requirement was not in the proposed rule, and in the preamble to the final rule [Part 98, October 30, 2009], EPA states that the only reason for adding this requirement is to "further EPA's understanding of the methods and equipment that reporters use, and to help better assess the appropriateness of the standard methods and industry practices that individual reporters select..." (74 FR 56343). The assurances of third party measurements are simply not needed in a system that already requires the highest accuracy. EPA's MRR requirements add considerable burden to the reporters without any real benefit to EPA. Some examples follow:

1. EPA requires that the reporter state the standard method or industry standard practice associated with each quantity measured. This MRR requirement would require the addition of a new, separate method of tracking and documenting these standards. The MRR requires new information to be obtained from third parties and tracked for reporting. This is burdensome and inappropriate when considering how accurate reporting companies need this information to be already.
2. EPA also requires that reporters certify the accuracy of third party meters. It is redundant and burdensome to require that reporters certify accuracy to third party meters that are already subject to existing internal and external controls. In many cases, the MRR reporter simply does

not have access to these third party records. Different vendors sometimes supply this data, and it is unnecessary to produce additional records to prove their accuracy.

These requirements add burden without benefit. Currently for reporters subject to reporting under Subpart MM, there are more stringent demands already placed on the exchange of materials at the point of custody transfer. The accuracy of measurement for this exchange of materials between a company and another party is extremely important to both parties, as it sets the basis for the financial exchange between the parties. The accuracy of these custody transfers is already ensured to a very high level. This transfer requires an accuracy that far exceeds the needs of a greenhouse gas emission reporting effort, and therefore the EPA's GHG Mandatory Reporting Rule should not add any additional requirements to ensure accuracy of custody transfer quantities.

API believes that EPA should exclude custody transfer measurements from the QA/QC reporting requirements of Subpart MM, NN and PP. Petroleum suppliers (refineries) and importers and exporters of record often do not own or operate the equipment used to transport or store materials including flow meters and tank gauges. Instead, the supplier or importer/exporter contract with wholly independent third parties approved and accredited by the U.S. Customs & Border Protection (CBP) to handle the transfer and laboratory analysis of materials. The quantities of materials are measured by protocols specified by a number of governing bodies, such as CBP, which has a rigorous program to ensure measurement accuracy on international shipments. Even on domestic shipments, there are already requirements and methods used by the involved parties to ensure accuracy in the custody transfer process.

It is redundant and burdensome for the EPA to require detailed monitoring and QA/QC, record keeping, and reporting on information on the equipment and measurements that are being reported for custody transfer amounts by third parties. This requirement adds effort and cost without benefit.

EPA has already made allowances exempting third-party custody-transfer meters from the QA/QC requirements of the MRR, such as the documentation, certification of method, and certification of accuracy. EPA allows exemptions for "billing meters," which are third-party custody-transfer meters. First, in the General Provisions of Subpart A, §98.3(i)(4), EPA allows the following exemption from the meter calibration requirements:

Fuel billing meters are exempted from the calibration requirements of this section, provided that the fuel supplier and any unit combusting the fuel do not have any common owners and are not owned by subsidiaries or affiliates of the same company.

Second, in the Stationary Fuel Combustion sources in Subpart C, EPA already allows exemptions for billing meters in §98.34(b)(ii) and (iii):

(ii) In addition to the initial calibration required by §98.3(i), recalibrate each fuel flow meter (except for qualifying billing meters under paragraph (b)(1)(iii) of this section) either annually, at the minimum frequency specified by the manufacturer, or at the interval specified by the industry consensus standard practice used.

(iii) Fuel billing meters are exempted from the initial and ongoing calibration requirements of this paragraph, provided that the fuel supplier and the unit combusting the fuel do not have any common owners and are not owned by subsidiaries or affiliates of the same company.

Billing meters were appropriately excluded by EPA for good reason. First, it is very difficult for the reporting entity to obtain all the records the EPA requires on a monitoring device and from an operation that is not owned nor controlled by the reporter. The reporter simply does not have the means to force the third party to supply all those records. Second, it is expensive and burdensome to duplicate and maintain a redundant file of the records maintained by a third party. Third, assurance of accuracy for custody transfer is simply unnecessary, since many other protocols and motivations already assure the accuracy of a custody transfer measurement. EPA should apply the same logic to Subparts MM, NN and PP and exclude custody transfer, especially where third-party measurement is involved, from the detailed QA/QC reporting requirements.

Some examples of the superior accuracy of the existing systems (without the new EPA MRR requirements) follow:

These records are the basis for reporting inventories as well as commercial purchase and sale payments. The parties making the exchange use industry consensus standards for measurement and calibration.

These financial records also have the benefit of being subject to audit under existing internal controls, Sarbanes-Oxley regulations, as well as the Internal Revenue Service (IRS), Customs & Border Protection (CBP) and other regulatory compliance systems.

International custody transfer shipments are tightly controlled already:

1. The existing financial records already contain volumes (or weights) for all materials that are shipped into or out of a facility identified by material-specific codes. For imported fuels, CBP is the federal agency tasked with enforcing regular requirements around calculation of imported quantities of bulk petroleum feedstocks and products.
2. 19 CFR§151 Examination, Sampling and Testing of Merchandise details the requirements and Subpart C of 19 CFR§151 deals specifically with petroleum and petroleum products. The CBP in its guideline for approval and validation of FTZ petroleum measurement systems (including sampling) state that petroleum measurement systems must be approved (i.e. 19 CFR 151.42(a)(1)(i) and 151.42(a)(3)) and are typically accepted if those petroleum measurement systems “meet or exceed the installation, operational, and performance criteria found in the “appropriate” (sic current edition) API Manual of Petroleum Measurement Standards (MPMS).
3. For marine movements, third party gaugers bonded and approved by CBP’s Laboratory and Scientific Services group are to be employed to objectively determine quantities of

bulk petroleum materials being imported at refineries and chemical plants. Subpart C of 19 CFR§151 deals specifically with petroleum and petroleum products.

4. Third party gaugers are approved by CBP prior to carrying out any marine measurement work and they are tasked with assuring the accuracy of the data. CBP periodically audits third party gaugers to ensure their practices and equipment are in accordance with industry requirements.

5. The CBP program also applies to some refinery feedstocks. For pipeline movements into the United States, CBP requires that a custody transfer meter on the pipeline be determined, and the importer must certify to CBP that the meter was installed in accordance with API or ASTM guidelines, that the meter is proved/calibrated on a basis in accordance with its usage, and that records relating to the installation, care and operation of the meter are stored in an organized manner and available for CBP's review upon request. As the importer is often times not the owner/operator of the meter, contracts between meter owner and the importer are issued to convey the requirements.

Recommendations: API suggests that EPA consider the advantage of existing custody transfer and accounting systems, consider the precedent EPA has already set for billing meters, and consider the information contained here in for quantities measured by third parties. EPA should remove the other reporting, monitoring QA/QC, and recordkeeping requirements for third party custody transfer for subparts MM, NN, and PP. If EPA wishes to review any records during an audit, API suggests that the volumes in the reporter's financial records be the basis and be included in section §98.394 that would allow refineries, importers, and exporters to use existing accounting systems and quantities determined under the CBP and other third party programs.

API suggests the following change be made to provide an exemption similar to that given under Subpart A, specifically §98.3(i)(4) for third-party fuel billing meters.

Under§98.394 (Subpart MM), §98.404 (Subpart NN) and §98.424 (Subpart PP), API suggests the language should be modified to add the following:

Any equipment used in the determination of quantity not owned or operated by the reporting entity and used for billing or custody transfer purposes in this subpart is exempt from the monitoring and QA/QC requirements, data reporting requirements, and recordkeeping requirements specifically for information on the equipment and corresponding quantity measurement. Any records from third party equipment that are retained as part of normal business operations will be preserved and made available as needed.

Response: No rule change has been made as a result of these comments. The changes to Part 98 suggested by the commenters are outside the scope of the specific amendments proposed for public comment in the Federal Register notice of August 11, 2010.

Other Subpart PP Comments

Commenter Name: Rich Raiders
Commenter Affiliation: Arkema Inc.
Document Control Number: EPA-HQ-OAR-2008-0508-2371.1
Comment Excerpt Number: 3

Comment: Several Subpart PP proposed changes appropriately clarify reporting requirements for carbon dioxide (“CO₂”) suppliers.

Response: EPA thanks the commenter for the input.

Commenter Name: Karin Ritter
Commenter Affiliation: American Petroleum Institute (API)
Document Control Number: EPA-HQ-OAR-2008-0508-2383.1
Comment Excerpt Number: 53

Comment: Clarification of applicability for carbon dioxide suppliers - The language in §98.421 should be corrected to exclude the source categories that are explicitly excluded by §98.420(b) and (c). API requests adding “and is not excluded from this Subpart by §98.420(b) or (c)” after the phrase “meets the requirements of §98.2(a)(4).”

Response: No rule change has been made as a result of these comments. The changes to Part 98 suggested by the commenters are outside the scope of the specific amendments proposed for public comment in the Federal Register notice of August 11, 2010.

15. COMMENTS ON ADMINISTRATIVE PROCEDURES (E.G., COMMENT PERIOD)

Commenter Name: David P. Tenny
Commenter Affiliation: National Alliance of Forest Owners (NAFO)
Document Control Number: EPA-HQ-OAR-2008-0508-2373.1
Comment Excerpt Number: 1

Comment: At the outset, NAFO notes that EPA’s notice of its proposed rulemaking fails to explain that its proposed revisions were also part of proposed settlements with UARG and others, which EPA recently circulated for public comment. See 75 FR 42,085 (June 20, 2010). The value of taking public comment on the proposed settlements is significantly undermined because EPA clearly failed to conduct any meaningful review of these comments before moving forward with the proposed rule. If EPA does not fully consider and respond to all of the comments it has received—on the proposed settlements and on the proposed rule—before taking final action, it risks acting in an arbitrary and capricious manner.

Response: While it would be optimal for EPA to be able to consider comments on proposed settlements before moving forward with related rulemakings, the schedule for completing the proposed revisions prevented EPA from considering the comments on the proposed settlement before publishing the proposed amendments. Nonetheless, EPA did carefully consider the comments on the settlement agreements before finalizing the agreements. Note, there is no obligation under section 113(g) of the Clean Air Act for EPA to respond to comments on settlement agreements, unless they are also provided as comments on a related rulemaking. All of the comments submitted on the proposed settlements that were also submitted on the proposed rule amendments have been fully considered by EPA in developing the final rule amendments.

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2008-0508-2383.1

Comment Excerpt Number: 12

Comment: Since EPA has yet to release the e-GGRT for public review and comment, API requests EPA describe in the response to comments or the preamble to the final amendments the mechanism for submitting documents via e-GGRT.

Response: The subject of submitting documents via e-GGRT is beyond the scope of the rule amendments published for public comment on August 11, 2010. EPA will be providing guidance on the e-GGRT through separate action and outreach to facilities and suppliers.

16. COMMENTS ON LEGAL AUTHORITY FOR THE AMENDMENTS

Commenter Name: D.N.M. Robinson

Commenter Affiliation: None

Document Control Number: EPA-HQ-OAR-2008-0508-2349

Comment Excerpt Number: 1

Comment: The EPA is exceeding its congressionally determined authority, most recently in Texas in the matter of requiring filings that could jeopardize schools, churches and small businesses. EPA has become the loudest in a now shrinking choir of "global warming" alarmists, but the motive is less about air than about power.

Response: This comment appears to be outside the scope of the specific amendments to the GHG Reporting Rule proposed for public comment in the Federal Register notice of August 11, 2010. Note that the legal authority for Part 98 and the proposed amendments is described in the preambles to the proposed and final Part 98 (74 FR 16448, April 10, 2009, and 74 FR 56260, October 30, 2009), as well as the Response to Comments document for the final rule.

17. GENERAL SUPPORT AND OPPOSITION FOR THE AMENDMENTS

General Support for the Amendments

Commenter Name: Anonymous

Commenter Affiliation: None

Document Control Number: EPA-HQ-OAR-2008-0508-2345

Comment Excerpt Number: 1

Comment: I am in full support of the proposed rule covered in docket ID No. EPA-HQ-OAR-2008-0508. The revisions in this rulemaking, which according to the EPA website, would “provide additional clarification where Part 98 was vague or led to confusion among reporters, amend specific provisions related to certain issues identified as a result of working with the affected sources during rule implementation and outreach, [and would include] corrections to terms and definitions in equations and other technical corrections.” The revisions to the pertinent subparts, namely A, C, D, F, G, P, V, X, Y, AA, OO, and PP, would allow for clear-cut guidance on the regulation and would allow for better reporting through the EPA Greenhouse Gas Reporting Program (GHGRP).

Response: EPA thanks the commenter for the input.

Commenter Name: Anonymous

Commenter Affiliation: None

Document Control Number: EPA-HQ-OAR-2008-0508-2353

Comment Excerpt Number: 1

Comment: The proposed rule to make specific provisions in the greenhouse gas reporting rule by clarifying certain provisions as well as correct technical errors along with editorial errors in my opinion will provide a more thorough understanding and interpretation of the rules stated in Part 98 of the proposed rule. The definitions of words and phrases that previous existed in the original mandatory report allow for owners and operators of facilities to obtain a greater understanding of the tasks they must perform in order to report their facilities green house gas emissions correctly.

Response: EPA thanks the commenter for the input.

Commenter Name: C. Maddox

Commenter Affiliation: None

Document Control Number: EPA-HQ-OAR-2008-0508-2356

Comment Excerpt Number: 1

Comment: While I am not for an excessive amount of Government control, when it comes to things like protecting our environment, the public and our natural resources I agree that there is an increasing need for rules and regulations that work toward ensuring the greater good. I am in

favor of these proposed regulations. It is important for industrial companies to truthfully report GHG emissions and work toward a goal of limiting those emissions in order to protect our already deteriorating Ozone. Our world is in trouble due to negligence and carelessness. I am all for revising the GHG Reporting Program to include technical corrections, ensure consistency and provide clarification. This is extremely important in ensuring that companies can and will abide by these regulations because it leaves little to no room for error.

In short, I support the proposed regulatory measures on the assumption that the EPA is acting in the best interests of the general public and our environment. Thank for taking the time to review my comment.

Response: EPA thanks the commenter for the input.

However, it is important to clarify that the GHG reporting program does not include any provisions to specifically limit emissions of chemicals that deplete stratospheric ozone, although some of the chemicals that are known to act as greenhouse gases are also known to be ozone depleting substances. The protection of stratospheric ozone is addressed by other regulations promulgated under other Clean Air Act authority.

Commenter Name: Anonymous

Commenter Affiliation: None

Document Control Number: EPA-HQ-OAR-2008-0508-2353

Comment Excerpt Number: 3

Comment: Overall, I believe the this proposed rule was developed with the thoughts and concerns of owners and operators in mind and therefore this proposed rule is in my opinion a necessity to make the burden of reporting greenhouse gas emissions lessen as well as provide a more clear and comprehensible rule.

Response: EPA thanks the commenter for the input.

Commenter Name: Lorraine Krupa Gershman

Commenter Affiliation: American Chemistry Council

Document Control Number: EPA-HQ-OAR-2008-0508-2368.1

Comment Excerpt Number: 1

Comment: ACC generally supports EPA's proposed revisions to the mandatory reporting rule (MRR) for greenhouse gases (GHGs). We recognize that EPA has been under extraordinary pressure to issue the final MRR and to begin reporting data for the 2010 year beginning January 1, 2011. The proposed revisions found in this package are the result of detailed discussions with impacted trade associations and companies, and generally reflect a more flexible approach to the MRR.

Response: EPA thanks the commenter for the input.

Commenter Name: Rich Raiders

Commenter Affiliation: Arkema Inc.

Document Control Number: EPA-HQ-OAR-2008-0508-2371.1

Comment Excerpt Number: 1

Comment: In general, Arkema supports many aspects of the proposed rule, and recommends opportunities for EPA to strengthen the rule before any final promulgation. We appreciate the significant effort EPA expended in making these amendments. In general, the proposal clarifies several critical aspects of the existing Part 98 climate change reporting system.

Response: EPA thanks the commenter for the input.

Commenter Name: William C. Herz

Commenter Affiliation: The Fertilizer Institute (TFI)

Document Control Number: EPA-HQ-OAR-2008-0508-2376.1

Comment Excerpt Number: 1

Comment: TFI supports EPA's proposed amendments to 40 C.F.R. Part 98, Subparts G, V, and PP and encourages EPA to adopt these amendments. Specifically, TFI supports (1) deleting the requirement to report the nitrogen content in synthetic fertilizers from Subparts G and V, (2) deleting the requirement to report urea uses from Subpart G, (3) deleting Equation G-6 from Subpart G, relating to the waste recycle stream, (4) clarifying in Subpart G that reported CO₂ emissions from an ammonia manufacturing facility may include CO₂ that is used on-site in the manufacture of urea and, as such, is not an emission to the ambient air from the ammonia manufacturing facility, (5) making changes to Subpart PP to allow more flexibility when determining the amount of CO₂ sent off-site by allowing use of weigh bills, scales, or load cells, and (6) providing flexibility in Subpart PP when a source uses a flow meter to measure CO₂ sent off-site regarding where that flow meter may be installed.

Response: EPA thanks the commenter for the input.

General Opposition To The Amendments

Commenter Name: Helen D. Silver

Commenter Affiliation: Clean Air Task Force et. al

Document Control Number: EPA-HQ-OAR-2008-0508-2403.2

Comment Excerpt Number: 4

Commenter Name: Craig Holt Segall

Commenter Affiliation: Sierra Club Environmental Law Program et. al

Document Control Number: EPA-HQ-OAR-2008-0508-2398.3

Comment Excerpt Number: 5

These two commenters submitted identical comments on this subject.

Comment: General Assessment

EPA's proposed changes would weaken the rule, but EPA does not consider them cumulatively to determine how much damage they will do. While we oppose these changes, we ask EPA nonetheless to conduct such a calculation, documenting the increased uncertainty, error rates, and other rule failures the changes are likely to cause on a cumulative basis. EPA should not be moving forward on any of these changes without assessing their impact on the rule as a whole.

Response: As indicated in the responses to other comments on the proposed amendments to the various subparts in Part 98, we disagree with the commenters' assertion that the proposed changes would weaken the rule and increase the uncertainty or error rates associated with the GHG emissions data submitted under Part 98.

We are confident that the monitoring and QA/QC procedures in Part 98, along with the GHG Reporting Program's data verification procedures, will ensure that the data collected under the GHG Reporting Program will be of sufficient quality to meet the program's objectives.

Commenter Name: Anonymous

Commenter Affiliation: None

Document Control Number: EPA-HQ-OAR-2008-0508-2346

Comment Excerpt Number: 1

Comment: We are trying hard to comply with the Greenhouse Gas Reporting regulations. However, EPA has issued so many changes to the original Final Monitoring Requirements that we are getting more and more confused. I have calculated emissions for 20 years and I have never found an emission so easily calculated as the GHG made so complicated.

As to making any worthwhile comment on a single one of the many changes is not possible until EPA decides what they are doing. Please, please stop making reporting GHG emissions so difficult.

Response: EPA thanks the commenter for the input. EPA appreciates the commenter's concern over the complexity of the Part 98 requirements for calculating and reporting GHG emissions. However, the overall approach and complexity of estimating and reporting GHG emissions for different industries is driven in part by the goal of providing flexibility to accommodate the needs of a number of different reporters.

As explained in the preamble to the proposed rule amendments (75 FR 48747-48748, August 11, 2010), we have identified errors in the regulatory language as a result of working with affected industries to implement the various subparts of Part 98. We have also identified certain rule provisions that should be amended to provide greater clarity. Finally, we proposed revisions to provide additional flexibility for certain requirements based in part on a better understanding of

various industries. The majority of those amendments are now being promulgated as proposed, and the remainder have been modified since proposal based on comments and input from the affected industries and other interested parties. In many cases, the revisions that are being made simplify the estimating and reporting of GHG emissions and reduce the burden on those facilities required to report GHG emissions.

18. COMMENTS ON PART 98 ISSUES THAT WERE COVERED BY THE FIRST PART 98 CORRECTIONS NOTICE

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2008-0508-2383.1

Comment Excerpt Number: 55

[This commenter suggested several changes to subpart MM – Suppliers of Petroleum Products.]

Comment: Subpart MM Calibration Timing - In §98.394(b)(1) under ‘Equipment Calibration’ the rule states, “(1) All measurement equipment shall be calibrated prior to its first use... using an appropriate standard method... (2) Measurement equipment shall be recalibrated at the minimum frequency specified by the standard method used or by the equipment manufacturer’s directions.”

This section of the rule is inconsistent with §98.3(i)(6) where EPA recognizes that for continuously operating units some calibrations are not possible on-line without disrupting operations and goes on to state, “In such cases, the owner or operator may postpone the initial calibration until the next scheduled maintenance outage, and may similarly postpone the subsequent recalibrations. Such postponements shall be documented in the monitoring plan that is required under §98.3(g)(5).”

Recommendations: EPA should amend the text for subpart MM to make it consistent with the flexibility afforded by subpart A.

Calcine Coke (also known as calcined or calcinated coke) - Table MM-1 contains default data for petroleum coke but does not contain corresponding data for calcine coke. Petroleum coke and calcine coke have different uses, and calcine coke typically has a higher carbon density than petroleum coke due to the calcinations process. Because of these differences, it is probably not appropriate to utilize the petroleum coke data for reporting on calcine coke under Subpart MM.

Product quality requirements for calcine coke results in a product that has very little variability in its carbon share. However, without default data in Table MM-1, calcine coke producers would be forced into a burdensome sampling program for calcine coke reporting under subpart MM. API is requesting that EPA include applicable calcine coke data in Table MM-1 to prevent the waste of time, money, and effort that would otherwise be imposed on reporters.

Recommendation: API is recommending the addition of new default factors for Calcine Coke in Table MM-1: Average Calcine Coke Carbon Content: 96.95%; Calcine Coke Density: 0.1910 Metric Tons/Bbl; Emission Factor: 0.6462 Metric Tons CO₂/Bbl

Corrections to Table MM-1: The densities shown for ethane, propane and butane differ from values commonly used by the oil and gas industry. EIA's Inventory of U.S. Greenhouse Gas Emissions and Sources (which is cited by the API Compendium) uses 0.0592 tonnes/bbl for ethane, 0.0804 tonnes/bbl for propane, and 0.0926 tonnes/bbl for butane.

Recommendation: API requests that the densities be updated consistent with values commonly used by the oil and gas industry.

Response: No rule change has been made as a result of these comments. The changes to Part 98 suggested by the commenter are outside the scope of the specific amendments proposed for public comment in the Federal Register notice of August 11, 2010

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2008-0508-2383.1

Comment Excerpt Number: 56

Comment: Section 98.407 is titled "Records that must be retained," but states that the information must be contained in the annual report.

Recommendation: We believe EPA meant this to state, "All reporters shall retain copies of the following information." API requests that this be corrected.

Response: The commenter is correct that the introductory text to 40 CFR 98.407 should have referred to records that should be kept by the reporting entity, and not information to be included in the annual report. However, no rule change has been made as a result of this comment. The change to Part 98 suggested by the commenter is outside the scope of the specific amendments proposed for public comment in the Federal Register notice of August 11, 2010, but will be considered for future rulemakings.

Commenter Name: Karin Ritter

Commenter Affiliation: American Petroleum Institute (API)

Document Control Number: EPA-HQ-OAR-2008-0508-2383.1

Comment Excerpt Number: 52

Comment: Clarification of applicability for suppliers of natural gas and natural gas liquids – The language in section §98.401 should be corrected to exclude the source categories that are explicitly excluded by section §98.400(c). Recommendation: API requests adding "and is not excluded from this Subpart by §98.400(c)" after the phrase "meets the requirements of §98.2(a)(4)."

Response: No rule change has been made as a result of this comment. The changes to Part 98 suggested by the commenter are outside the scope of the specific amendments proposed for public comment in the Federal Register notice of August 11, 2010. We would note that we do not believe the proposed clarification is needed, as the industries listed in §98.400(c) are clearly excluded from the source category.

19. GENERAL OUT OF SCOPE COMMENTS

Commenter Name: Anonymous

Commenter Affiliation: None

Document Control Number: EPA-HQ-OAR-2008-0508-2351

Comment Excerpt Number: 1

Comment: Even in light of actual research, and "doctored" research allegedly supporting global warming, you persist in pushing regulations to limit a gas that is the normal byproduct of every living organism and required by every living plant. This sounds like an agenda, not science. The public is clearly not in favor of such limitations, so the government tries an "end around."

Response: This comment is outside the scope of the specific amendments to the GHG Reporting Rule proposed for public comment in the Federal Register notice of August 11, 2010. Note that the legal authority for Part 98 and the proposed amendments is described in the preambles to the proposed and final Part 98 (74 FR 16448, April 10, 2009, and 74 FR 56260, October 30, 2009), as well as the Response to Comments document for the final rule.

Commenter Name: Gordon Arbuckle

Commenter Affiliation: Patton Boggs LLP

Document Control Number: EPA-HQ-OAR-2008-0508-2386.1

Comment Excerpt Number: 1

Comment: As EPA was advised during the earlier comment process, the GHG reporting regulations are critically deficient because they fail to require submission of the information necessary to assess the questions of (1) whether, and to what extent, intensive U.S. based regulation of GHG emissions will result in "leakage" – or migration of energy intensive manufacturing operations to countries with less stringent regulatory regimes resulting; and (2) whether, and to what extent, that shift will result in a net increase in worldwide GHG emissions.

GHG Reporting Rules which do not provide for the development of the data required to assess the impact of regulation of emissions from U.S. sources, without commensurate regulation of the

sources which power the competitive foreign industries, are not responsive to Congress' expectations in enacting the Consolidated Appropriations Act. Without that data, neither EPA nor the Congress will be able to meaningfully consider the critical question of whether stringent U.S. regulation, without global balance or border adjustment mechanisms, might actually result in both damage to U.S. jobs and the manufacturing sector and net increases in global GHG emissions. Such a result would directly contradict the Administration's often announced policy of restoring and protecting the U.S. manufacturing sector and saving and creating U.S. jobs. Moreover, the inability to credibly answer the fundamental question of whether U.S. regulations will increase or diminish global GHG emissions would call into question the legality of any GHG emission limits which the EPA might adopt in the future.

In short, because the GHG Reporting Rules, as they currently stand, do not require information regarding upstream emissions associated with the production of high carbon intensity products exported to the U.S., they cannot develop the information required to properly devise a regulatory scheme under either the Clean Air Act or any of the legislation pending in the Congress. They will not provide the information required to assess the regulatory and environmental effects of any such regulations, to assess impacts on U.S. employment and the manufacturing sector, or to measure the regulations' effectiveness in achieving the objective of reducing worldwide greenhouse gas emissions. In the absence of a viable information base, regulatory decisions respecting GHG will be necessarily arbitrary and unsupported by scientific evidence. EPA is dealing here with a global issue and must develop the information required to assess worldwide effects as well as those which occur within the U.S. It is essential that the GHG Reporting Rules provide the basis for collection of the full suite of information and metrics required to effectively address issues of climate control without inadvertently causing net increases in global GHG emissions or unnecessarily damaging key U.S. industries with resulting loss of U.S. jobs.

EPA, in making regulatory decisions under either the Clean Air Act or some new legislation will face these questions, both in phasing and in assessing environmental effects and regulatory impacts. The Agency will not be able to make decisions which will survive judicial review unless it has scientific evidence to support its decisions. The GHG Reporting Rule, as it currently stands, will not obtain this information or assure appropriate consideration of it. We are aware that, when similar comments were submitted previously, EPA responded that "the collection of economic data and data on the regulatory frameworks of other countries, the performance of economic impact analyses of potential future regulatory programs, and the determination of the global GHG impacts if companies were to move production overseas due to a future program is beyond the scope of the reporting rule." We are also aware that the Notice for this proposed rulemaking is explicit to the effect that only the technical issues addressed in the Notice will be considered.

We would point out, however, that: (1) EPA has not promulgated the regulations it was directed to promulgate and is now over three years in breach of a statutory duty. (2) That breach imperils the Agency's ability to credibly support any GHG regulations it may currently be considering. (3) Failure to collect and assess the data required to ultimately enact legislation that will avoid unnecessary loss of jobs and manufacturing capacity is contrary to Administration policy and adverse to the public interest.

If new carbon controls are implemented for energy-intensive/internationally competitive industries, the adverse competitive effects could be substantial. Costs could rise; prices could rise; long established customers could turn to foreign companies operating in countries that have less developed environmental standards and regulatory authority.

If it is not clear how much U.S. production would be displaced or lost to other less stringently regulated countries, then it will be impossible to determine the impact of any U.S.-only regulatory regime. It is likely that, without regulatory accommodations, U.S.-only regulation of GHG emissions from energy intensive industries will result in loss of US-based jobs; economic disruption and dislocation; and possibly also in the unintended consequences of reduction of energy efficiency and increase in worldwide carbon emissions.

Failure to provide for the development of metrics and data to support assessment of business and jobs migration and its consequent effect on GHG emissions will substantially impede achievement of the primary objective: reducing worldwide GHG emissions. The proposed rules must be revised to require information addressing at least the following questions: What are the energy intensive U.S. industries subject to intense foreign competition? What is the likelihood and magnitude of anticipated production shifts in each such industry category? What are the relative life-cycle carbon emissions from U.S. products as opposed to those from likely exporters? What metrics should be used to measure? What is the likely net effect on worldwide GHG emissions of any regulatory approach under consideration?

An effective climate change program must encourage innovation and investment, while discouraging emissions migration and, with it, the loss of U.S. jobs. If manufacturing activities move from inside the U.S. to countries with weaker regulation and enforcement mechanisms in place, U.S. employment opportunities will decrease, while, at the same time, global greenhouse gas emissions will increase. Failure to obtain the information required to address this issue would be a fatal weakness in the foundation for any EPA GHG regulation program. Please provide a substantive response to these comments. To the extent that these comments are not addressed in these proceedings, please treat this submission as a petition for rulemaking.

Response: The subjects of the effect of U.S. GHG emission regulations on U.S. manufacturing, jobs, and global GHG emissions rates, and the data needed to estimate those impacts are beyond the scope of 40 CFR part 98 and these proposed amendments. Note that the legal authority for Part 98 and the proposed amendments is described in the preambles to the proposed and final Part 98 (74 FR 16448, April 10, 2009, and 74 FR 56260, October 30, 2009), as well as the Response to Comments document for the final rule. The process of amending Part 98 is not the appropriate forum for the discussion of these subjects. The topics identified by the commenter are likely to be the subject of future policy and scientific discussions. However, to the extent that accurate GHG emission estimates are needed to inform those discussions, the amendments to Part 98 will help provide those estimates.

Finally, a comment letter on these proposed amendments is not the appropriate avenue for submitting a petition for rulemaking.

Commenter Name: Anonymous

Commenter Affiliation: None

Document Control Number: EPA-HQ-OAR-2008-0508-2345

Comment Excerpt Number: 2

Comment: These regulations and reports will help businesses operate on a higher economically friendly level. As this is a world we all share, not only with other countries, but with future generations, the preservation of as much as possible is an imperative. On the topic of EPA verification of reported data, I also agree with what is in the docket. Even if the information has gone through a separate third-party verification process, I believe that it is the EPA's job to verify to their own standards, although, as written in their statement to the EPA, the Glass Association of North America ("GANA"), clearly disagree. It seems like they are just trying to have less work on their plate. In that same statement, they also request to have the initial date of reporting changed, stating the "EPA underestimates the time the flat glass manufacturing industry requires to compile, verify, and review the annual data needed for submittal..." I do not believe the EPA needs to change the original date as specified in the plan. Keeping these original dates and keeping the EPA in charge of verification takes away opportunities for corruption or the manipulation of GHG numbers.

Response: EPA thanks the commenter for the input.

No rule change has been made as a result of this comment. The subject of EPA's emissions verification approach is outside the scope of the specific amendments proposed for public comment in the Federal Register notice of August 11, 2010. Responses to public comments on EPA's emissions verification approach can be found in the preamble to the final Part 98 (74 FR 56282-56283, October 30, 2009), and in "Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Approach to Verification and Missing Data" (September 2009, EPA-HQ-OAR-2008-0508).

See EPA's response to comments in the section, "How these amendments apply to 2011 GHG emission reports," in this document for EPA's response on whether the dates of the initial reports or any of the other reporting requirements have been changed as a result of the amendments to Part 98.

Commenter Name: Peter Zalzal

Commenter Affiliation: Environmental Defense Fund (EDF)

Document Control Number: EPA-HQ-OAR-2008-0508-2370.1

Comment Excerpt Number: 2

Comment: Environmental Defense Fund (EDF) reiterates our long-standing request that EPA make public these BMM extension requests. We respectfully recommend that EPA list all of the companies and facilities that have requested to use BMM along with the status of those requests. This commitment to transparency is at the core of President's January 26, 2009 Executive Order and is consistent with EPA's commitment to public disclosure in its

Confidential Business Information proposal, where the Agency recognized that such disclosure is critical “because it ensures transparency and promotes public confidence in the data.” 75 FR 39094, 39097 (Jul. 7, 2010). Public disclosure of these requests will likewise help to promote accountability, ensuring that the public and polluters alike are aware of facilities that have yet to fully comply with the requirements of the final MRR.

Response: EPA thanks the commenter for the input.

No rule change has been made as a result of this comment. The subjects of transparency, confidential business information, and whether requests to extend the use of best available monitoring method (BAMM) should be made public are beyond the scope of the amendments to Part 98 published on August 11, 2010.

Commenter Name: Joel R. Hall

Commenter Affiliation: Mexichem Fluor Inc.

Document Control Number: EPA-HQ-OAR-2008-0508-2365

Comment Excerpt Number: 4

Comment: EPA states that it will rely on Agency verification of the electronic data provided in the annual reports in lieu of third-party verification. The agency further states that “sufficient information must be included in the electronic reports, at the facility, source category, and unit levels, to enable EPA to recalculate the reported GHG emissions and to quality-assure the data.” [75 FR 48762] Mexichem questions the need for the EPA to perform calculations. Programs such as the Toxic Release Inventory (TRI) are equivalent to the GHG MMR in that it is a reporting program. The agency does not calculate emissions under the TRI program and should not need to calculate them under the GHG MMR.

Response: No rule change has been made as a result of this comment. The subject of EPA's emissions verification approach is outside the scope of the specific amendments proposed for public comment in the Federal Register notice of August 11, 2010.

Commenter Name: Rhea Hale

Commenter Affiliation: American Forest & Paper Association (AF&PA)

Document Control Number: EPA-HQ-OAR-2008-0508-2382.1

Comment Excerpt Number: 5

Comment: The American Forest & Paper Association (AF&PA) has identified two technical errors in subpart TT of the EPA GHG rule (industrial landfills). Note that these errors are associated with the final rule amendments published on July 12 (not the July 20 proposed amendments).

The first error is in regard to the start year for quantifying waste deposits and calculating associated emissions. The text in Section 98.463(a)(2) states “determine annual waste quantities ... for each year starting with January 1, 1980 or the year the landfills first accepted waste if after

January 1980, up until the most recent reporting year.” However, the key to Equation TT-1 (which is used to calculate methane generation based on the quantified waste deposits) includes this description for S, the start year “use the year 1960 or the opening year of the landfill, whichever is more recent.” Also, the key to Equation TT-4 (which is used to calculate average annual waste deposition quantities during historic periods historic data is not available) includes a similar description for “YrOpen = year 1960 or the year in which the landfill first received waste from company records, whichever is more recent...” Therefore, it is unclear whether or not EPA intends for reporters to base calculations on data beginning in 1960, or in 1980.

The second error is in regard to the method presented for calculating a waste-specific DOCx value for waste streams using Equation TT-8 in Section 98.364(b)(4). The key to Equation 8 states that the result of the calculation (DOCx) is “degradable organic content of waste stream in Year X (weight fraction, wet basis).” However, the equation as provided would return a DOCx value on a dry basis.

Response: EPA thanks the commenter for the input. No rule change has been made as a result of this comment. The changes to subpart TT of Part 98 suggested by the commenter are outside the scope of the specific amendments proposed for public comment in the Federal Register notice of August 11, 2010.

Commenter Name: Joel R. Hall

Commenter Affiliation: Mexichem Fluor Inc.

Document Control Number: EPA-HQ-OAR-2008-0508-2365

Comment Excerpt Number: 3

Comment: Mexichem is concerned with the confidentiality of data submitted under 40 CFR 98.3(c)(5)(ii). Because this data will be reported in metric tons of GHG it could be used by competitors to the disadvantage of our business. The Data category assignments for reporting elements to be reported under 40 CFR part 98 and its amendments memo from Lisa Grogan-McCulloch, EPA/Climate Change Division and Ruth Mead and Amanda Baynham, ERG to EPA-HQ-OAR-2009-0924 dated June 28, 2010 indicates that data submitted under §98.3(c)(5)(i) and (ii) will not be confidential business information (CBI) [Table B-1: List of Data Elements in Proposed and Final Supplier Subparts, page 1 of 33]. Therefore, this data, which includes raw production data, will be available to the public. Mexichem requests that the EPA consider a means to protect the confidentiality of this data.

In addition, §98.3(c)(4)(iii) will require that Mexichem report annual emissions of each fluorinated GHG (including those not listed in Table A–1 of this subpart) expressed in metric tons under Subpart L. This data will include not only raw production data, but also raw material inputs, wastes removed from the process, etc. This data is not considered CBI under the Data category assignments for reporting elements memo and will therefore be available to the public. Access to this data by our competitors has the potential to cause a competitive disadvantage for us. Mexichem requests that the EPA consider a means to protect the confidentiality of this data.

Response: EPA thanks the commenter for the input. No rule change has been made as a result of these comments. No changes were proposed to 40 CFR 98.3(c)(5)(ii) in the August 11, 2010, proposed amendments. Likewise, no changes were proposed to 40 CFR 98.3(c)(4)(iii) for the reporting of each fluorinated GHG in the August 11, 2010, proposed amendments. The determination of which data elements will be considered to be CBI is not the subject of the August 11, 2010, proposed amendments. The subject of CBI determinations is being addressed by another proposed rule that was published on July 7, 2010 at 74 FR 39094 under docket EPA-HQ-OAR-2009-0924.

Commenter Name: Stephen E. Woock

Commenter Affiliation: Weyerhaeuser Company

Document Control Number: EPA-HQ-OAR-2008-0508-2375.1

Comment Excerpt Number: 12

Comment: A reference error in the new Subpart TT for Industrial Waste Landfills needs correction.

In addition to the proposed revisions to the GHG MRR, Weyerhaeuser believes there is a mis-directed reference (typographical error) in the current rule that should be addressed. In newly added Subpart TT Industrial Waste Landfills, [Footnote: 75 FR 39736; July 12, 2010.] at Table TT-1 the line item labeled “Inert Waste (i.e. wastes listed in §98.460(b)(3))” is in error. There is no §98.460(b)(3), and instead the reference should be to §98.460(c)(2). The latter refers to the listed inert waste materials that are important when using Equation TT-1.

Response: EPA thanks the commenter for the input. No rule change has been made as a result of this comment. The changes to subpart TT of Part 98 suggested by the commenter are outside the scope of the specific amendments proposed for public comment in the Federal Register notice of August 11, 2010.